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INDEPENDENT ASSESSMENT OF ENERGY POLICY MODELS:

TWO CASE STUDIES

by

THE M.I.T. MODEL ASSESSMENT GROUP

Energy Laboratory Report No. 78-011
May 1978

PREPARED FOR THE ELECTRIC POWER RESEARCH INSTITUTE
PALO ALTO, CA

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ABSTRACT

Energy policy models are playing an increasingly important and visible role in supporting both private and public energy policy research and decision making. As importance has increased so too has the need for model review and assessment to assist in establishing model credibility for users and those affected by model-based policy research. Toward this end EPRI has sponsored the M.I.T. Energy Laboratory in a one-year project to assess two important energy system models, the Baughman-Joskow Regionalized Electricity Model and the Wharton Annual Energy Model, and to identify and analyze organizational and procedural issues in the model assessment process.

PREFACE

This report was prepared by the M.I.T. Model Assessment Group. Participants included:

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Other contributors include Wayne Christian, Royce Ginn, John Train, and Cecilia Wong.

ACKNOWLEDGMENTS

We wish to acknowledge the contributions of Dr. Richard Richels, the EPRI Project Manager for this project. We have benefited substantially from discussions with Dr. Richels concerning the objectives of model assessment, as well as the details of our approach. Professor Martin Greenberger of Johns Hopkins University has also contributed significantly to our work, both by his own research and through discussion of the issues and our approach.

We also wish to acknowledge the assistance and counsel of an Advisory Panel including: Mr. Raymond Beauregard of Northeast Utilities Service Company, Mr. Robert Bigelow of the New England Electric System, and Mr. R. Taber Jenkins of the Tennessee Valley Authority.

Finally, we wish to acknowledge the contributions and patience of the modelers who interacted with us during the project. These include Professor Paul Joskow of the M.I.T. Economics Department; Dr. William Finan of the Economic Forecasting Unit, Wharton School of Management; Mr. Dilip Kamat of the Center for Energy Studies, University of Texas; and Professor Martin Baughman of the University of Texas. In particular, Professor Baughman has been most generous of his time and effort in providing us with the documentation, computer tapes, and computer listings necessary to support our activities, as well as participating in project review meetings. His openness and courtesy set a high standard for those who will follow in participating in the model assessment process.

EXECUTIVE SUMMARY

Background, Objectives, and Organization

In recent years policy analysis models have become increasingly important in the policy research process. This development is the result of simultaneous interaction of several factors, including most importantly: the desire of researchers of whatever discipline to extend research results to contribute to the process of policy research and analysis; the perception of those concerned with policy formulation and analysis that formal models can in fact contribute significantly and positively in the policy research process; and the availability of large-scale computational systems providing the capability to implement complex policy models for timely and efficient use in the policy research process. Energy policy models have been developed or sponsored by government agencies, including the National Science Foundation (NSF), the Department of Energy (DOE) and the Environmental Protection Agency (EPA); by industry, for example, Gulf Oil Corporation; and by research organizations, most prominently, EPRI.

While energy policy models are playing an increasingly important role in support of public and private energy policy analysis and decision making, we believe that the potential contribution is not yet fully realized. This is true for several reasons. First, the expectations of those sponsoring development of policy models may not correspond to reality. Second, modelers may lose sight of the policy issues comprising the subject of research as contrasted with the technical aspects of the underlying reality being modeled. Third, the need for organizational initiatives that facilitate communication between modelers and model users in both the model development and policy research process may not be realized. Finally, procedures for model review and assessment may not be sufficient to satisfy model users, or those affected by model-based policy analysis, as to the model's credibility.

This last obstacle to model credibility, and therefore utility, has been the subject of a one-year study by the M.I.T. Energy Laboratory. The objectives of the project have been two-fold:

- o to provide assessments of two important energy system models, the Baughman-Joskow Regionalized Electricity Model (REM), and the Wharton Annual Energy Model (WAEM); and

- o to analyze these assessment case study experiences to identify key organizational and procedural issues that must be addressed in the assessment process, and to develop a deeper understanding of the approaches to and objectives of policy model assessment.

In organizing the project, two closely related approaches to assessment were proposed: overview and in-depth. Overview assessment was defined to include review and evaluation of model documentation, both for model descriptions and for the results of model applications, and to exclude actual model operation. In-depth assessment, on the other hand, was defined to include actual "hands-on" examination and operation of the model and the associated data base. In-depth assessment then potentially involves replication of empirical content of the model, replication of previous applications, sensitivity analysis of model response to new data, sensitivity to changes in logical structure, and verification of model implementation. Both the overview and in-depth approaches were proposed in sequence for REM, and an overview assessment was proposed for WAEM.

Regardless of approach, the primary objective of policy model assessment is to evaluate the applicability of a model or set of models to analyze particular policy issues. There are three basic aspects to the assessment process, including: (i) evaluating the validity of the model's logical and empirical structure for a particular area of policy analysis; (ii) evaluating the accuracy of the implementation of the model; and (iii) evaluating the usability of the model. Model validation is ultimately the process of developing an informed opinion about the logical and empirical structure of the model based upon analysis of the objectives of the model, and the correspondence between the model and the state of knowledge about the processes being modeled. Verifying the accuracy of model implementation, on the other hand, is a more precise process involving a determination of the correspondence between the stated objectives of the modeling effort and the implemented model embodied in computer codes, users' guides, and associated materials. Evaluating usability involves assessing the efficiency with which the model may be used, as well as its flexibility and extensibility for new applications.

Assessment of the Regionalized Electricity Model (REM)

Description of REM: REM is a model of the U.S. electric power sector that combines submodels of electricity demand, supply, and the financial/regulatory process. The demand submodel projects electricity and competing fuel demand by state separately for the residential and commercial sector, and for the industrial sector. Important independent variables include population, gross national product, personal income, and industrial value-added and fuel prices, including the price of electricity. The demand submodel is formulated with an explicit rate of adjustment process to distinguish short- and long-term adjustments to changes in relative fuel prices. The model parameters are estimated using econometric methods.

The electricity supply submodel projects the capacity expansion, generation mix, transmission and distribution costs and investments for each of the nine census regions. Capacity expansion is projected for eight plant types, including peaking units, coal, oil, gas, LWR-uranium fuel cycle, LWR-plutonium fuel cycle, LMFBR, and HTGR, with hydro specified independently. The model projects expansion by plant type assuming that utility investors minimize annualized costs. Annualized costs depend explicitly upon expected electricity demand, capital costs and maximum capacity factors by plant type, projected values of fuel prices and operating costs, the shape of the load duration curve, and the construction lead times by plant type. In capacity expansion, values for demand and for fixed and operating costs are projected as linear extrapolations of historical values.

Generation mix decisions for the nine plants are based upon minimizing variable costs subject to the constraint of the load duration curve. The transmission and distribution (T&D) component of the supply model determines the T&D costs associated with meeting current demand, as well as new investments necessary to meet projected future demand. This component is based upon a regression model with demand and number of customers by sector as the principal explanatory variables.

The financial/regulatory submodel projects the capacity financing schedule and the price of electricity based upon the plant capacity and the T&D structure of the industry, the interest rate, an allowed rate of return, and a set of accounting rules as to what is included in the rate base. Equity, stock issue, and debt financing instruments are all considered, with independent limits imposed for each financial instrument based on prudent financial management. Capacity expansion that cannot be financed by traditional means is assumed to be financed by a hypothetical state power authority.

General Assessment of REM: REM represents an innovative and generally successful effort to model the demand, supply, and financial/regulatory components of the electric power sector. The most innovative aspect of the model is the consistent integration of these components, a characteristic unique to this model so far as we are aware. The modular organization of the model facilitates use in policy analyses and in general contributes to flexibility and to potential for extension and modification for new policy applications.

Documentation -- REM documentation is superior to that of most similar models with which we are familiar. The research results upon which the model is based are carefully reported in a series of technical reports, journal articles, and in a book, parts of which were available to us in the latter stages of the assessment. The model implementation is, however, not well documented, and a number of discrepancies between the available documentation and the implemented model were discovered.

Usability of REM -- In general, REM is useful for a wide range of policy analysis applications of interest and importance to the electric power industry. However, the potential user should be cautioned that the model has not been implemented in a manner that facilitates use by those unfamiliar with its intricacies and peculiarities. Either the applications must be made by the modelers, or the user must invest a substantial effort (perhaps 2-4 person-months) to assimilate the model, learning to use it, and interpret the model results. Redesigning the model implementation and providing adequate user documentation would be a moderately difficult undertaking. Any potential user who is planning extensive use of the model should consider this investment.

Model Structure -- Several general observations relate to the model structure, and should serve to caution potential users regarding restrictions on model applicability, and interpretation of model applications. First, the process by which capacity expansion and generation mix decisions are made in the electric utility industry is central to almost all actual and potential applications of REM. The REM modeling approach imparts an "all-or-nothing" character to the process since capacity expansion and generation decisions are based upon cost considerations alone. Thus, when relative costs between two competing plant types are close, a small change may result in a reversal of investment and/or operating behavior. Aversion to risk, resource limitations, expectations, and other factors that might potentially influence investment and operating decisions are not considered. REM shares this characteristic with all other related models with which we are familiar.

Second, the potential user should be aware that the procedure used to forecast future values for such variables as the electricity demand used in capacity expansion planning, as well as future capital and operating costs, has a major effect upon the model results. The procedure involves a linear extrapolation of historical values giving more weight to recent values. In experiments that included arbitrary changes in the weighting scheme, the model results, especially the mix between nuclear and coal, changed significantly. Similar results were obtained when a more complicated forecasting procedure was substituted for the linear procedure. The potential user is cautioned to ensure that the results of a particular policy analysis are not sensitive to changes in this forecasting procedure. In the future, consideration should be given to improving this aspect of the model.

Finally, the user should be cautioned to check two aspects of a model solution in the process of interpreting results. First, the model provides for nuclear generation to exceed that indicated by the maximum capacity factor when demand exceeds total capacity in a region. No warning of this condition is provided, although the actual capacity factor can be found in the output. Second, the possibility of financing from the fictional State Power Authority should always be checked since when this occurs interpretation of the results as a projection of a potential "future" is impossible.

Assessment of REM in Specific Applications: The ultimate objective of policy model assessment is to draw conclusions about the model's applicability in analyzing particular policy issues. REM has been employed by the modelers in a variety of policy analysis applications, including:

Electric Load Management (peak load pricing)
Changes in Cost Factors (fuel prices, capital costs, taxes)
Primary Energy Supplies (uranium availability)
Financing Costs
Regulatory Policies (rate of return, rate base)
Capacity Expansion Lead Times
Environmental Restrictions (equipment, operating costs)

Other potential application areas for which the model was intended, but has not yet been used, are:

Electricity Demand (taxes, conservation)
New Technology Assessment

We now summarize the results of the assessment as applied to each of the actual and potential policy analysis areas to which REM has, or might, be applied. In our opinion, REM is a useful analytical tool for application in these policy areas. The summary of assessment results tends, therefore, to focus upon certain limitations and/or aspects of model structure and implementation of which a potential user should be aware in interpreting model results.

Load Management -- REM treats the load duration curve (LDC) as exogenous. Hence the impact upon the LDC of any load management policy, such as peak load pricing, must be analyzed separately. Given such a side calculation, the model can be used in analyzing the consequences for total demand -- since changes in the LDC will change the regulated electricity price -- and for expansion and generation mix decisions. REM seems comparable with other models in this regard. Extending the model to endogenize the LDC will certainly require a new research effort.

Cost Factors -- REM provides a convenient framework for analyzing any policies that can be simulated in terms of changes in input factor costs including capital, fuel, and operating/maintenance costs. The analyst should be cautioned on two points. First, due to the optimization logic of REM (mentioned above), care should be taken to identify situations where a change in factor costs will lead to a dramatic shift in expansion plans or generation mix. Second, the user should note that the input values for capital and operating cost that he provides are not those actually used in expansion planning, since "future" values for these variables are projected by a linear forecasting procedure under the assumption that that is how the utility forecasts these variables. Thus, policy studies that involve analysis of changes in expansion plans due to changes in cost factors should be carefully interpreted.

Resource Availability -- REM's ability to analyze changing resource supply conditions is, excepting uranium, restricted to situations in which the change can be represented as a change in supply price. For example, REM assumes that utility coal demand does not influence the price of coal. This will be true if utility coal demand is small relative to total demand and/or if the coal supply function is relatively elastic. For uranium the model does provide an option to specify a cumulative cost/production schedule, which is then used in calculating nuclear fuel cycle costs.

Capacity Financing and Regulatory Issues -- As noted, a unique feature of REM is the existence of the financial/regulatory submodel. The model seems well suited for use in analyzing issues involving capacity financing and electric power sector regulation. One caution, noted above, is the fictitious nature of the State Power Authority (SPA) financing source. Existence of SPA financing provides a summary measure of disequilibrium and as such is useful. However, the model results have no legitimate interpretation when capacity is financed by this source. Elimination of SPA financing to obtain interpretable results requires the user to make changes in input variables and/or in the rules representing the regulatory process. This is not too difficult, but the model provides no help in this adjustment process.

While most regulatory issues are readily addressed by the model, one exception should be noted. There is presently no way to exclude noneconomic capacity from the rate base prior to the end of its service life (40 years). Further, at present all plant types have the same service life, an unlikely situation. Greater flexibility is required in this regard and would be relatively difficult for users to implement.

Construction Lead Time -- While the model is useful in analyzing the consequences of policies that affect construction lead times, the user should be cautioned that at present certain changes will produce erroneous results. Program errors result if lead times are changed by more than 2.5 years. Further, the logic of the computer program is such that nuclear must exceed coal contruction lead times. Finally, only the nuclear lead time is set as a parameter. Lead times for other plant types must be changed by appeal to the computer code, with little or no documentation of where the changes must be made.

Environmental -- Environmental constraints can be handled in the model only to the extent they can be interpreted as changes in cost factors. Moreover, the model cannot analyze situations where the technical characteristics of a given plant type change over time due to environmental regulation (adding scrubbers, etc.) nor can the model deal with changes due to environmental regulations taking effect in the future even when the regulations can be reflected in cost changes (because the forecasting procedure cannot be overridden). Finally, regulation in the form of siting either plants, or transmission and distribution facilities cannot be considered.

Technology Assessment -- REM as presently configured is not well suited for technology assessment. First, the model planning horizon (to 1997) is too short to consider the potential for most emerging technologies. Second, it is very difficult to specify new plant types in the model, either for a conventional technology (e.g., baseload versus cycling coal) or new generating type (central station solar). Extending the model for use in this type of application is likely to require a major redesign of the model implementation.

Demand -- In general, the formulation, implementation, and application of the REM demand submodel seems reasonable. Along with similar models the REM demand submodel does not explicitly represent the efficiency and utilization of energy-using appliances and structures. The model is useful for analyzing changes in electricity demand in response to policies that influence fuel prices, or the various independent variables (e.g., population, GNP) determining demand. However, the model is not useful for analyzing nonfuel price conservation policies (efficiency regulation, investment tax credits) that require an explicit representation of energy-using appliances and/or structures.

Assessment of the Wharton Annual Energy Model (WAEM)

Initially we proposed to conduct an overview assessment of the WAEM. However, as this effort was initiated, it became clear that at its current stage of development and documentation the model could not be assessed without very close interaction with the modeler. After discussion with both the modeler and with the EPRI Project Manager, it was concluded that an "independent audit" of the modeling effort and of a prototype version of the model was appropriate.

The WAEM involves a major adaptation of the Wharton Annual model to include a detailed characterization of the energy sector. Since very little documentation of the extended model was available at the time of the assessment, the independent audit consisted primarily of specifying a set of simulation experiments designed to assess the prototype model's performance regarding economic growth and energy system response. The results of these experiments were discussed with EPRI and the modelers. Given the preliminary nature of the model at that time, it was agreed that reporting the details of the experiments in this report was inappropriate, since the results would be rapidly outdated by further model development. From our point of view, the most interesting aspect of this part of the project was the recognition of independent audit as a legitimate approach to assessment, and obtaining experience in organizing and conducting an assessment involving this approach.

Approaches to Assessment

From our experience we believe that the overall model assessment process consists of four principal elements or stages:

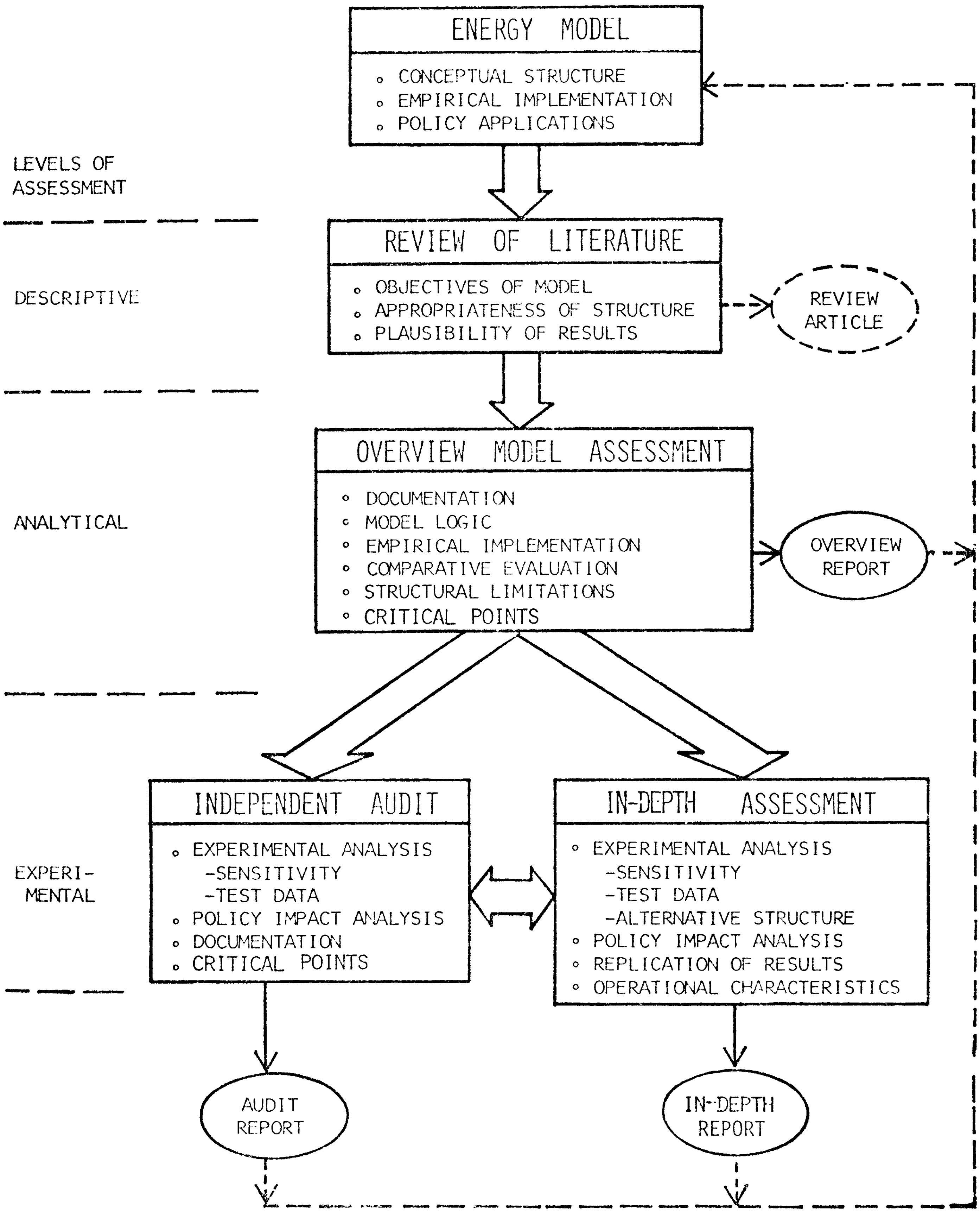
Review of literature,
Overview assessment,
Independent audit, and
In-depth assessment.

A summary of the content and relationships among these elements is given in the figure below. A review of literature is an essential first step in any assessment process, but is essentially a descriptive, not an evaluative, procedure. A review article can offer a useful description of a model's objectives and methodology, but it cannot provide an assessment of the model's capabilities.

An overview assessment uses the underlying technical documentation, especially the computer code, to develop a more precise analysis of the model's structure and implementation. An overview report can identify a model's critical points, but it will only occasionally be able to pass judgment on the adequacy of the model's treatment of them. The overview report is a useful intermediate stage in the assessment process, but assessment of the model's validity and applicability generally requires the acquisition and analysis of experimental data.

An independent audit evaluates a model's behavior by analyzing data derived from experiments that are designed by the assessors but run by the modelers. An important element of the procedure is that a member of the assessment group must be present "looking over the modeler's shoulder" while the experimental runs are being made. This is essential to the accurate interpretation of the results produced by the experiment. An audit report should use the experimental data together with the analytical material developed in previous stages of the assessment process to evaluate the model's validity in as many key areas (critical points) as possible. Audit procedures have the advantages of being relatively quick and inexpensive. With complex models, however, there will generally be some critical points that cannot be fully evaluated through an audit.

APPROACHES TO ENERGY MODEL ASSESSMENT



An in-depth assessment develops experimental data through direct, hands-on operation of the model. Direct operation makes it feasible to carry out more complex tests, particularly when the tests require modifications in model structure rather than simple changes in model parameters or data. An in-depth assessment is a substantial undertaking that can entail significant costs, but if the model is being considered for serious policy analysis, the potential payoff is likely to far exceed the cost. It is usually most efficient to conduct exploratory analysis through an independent audit before embarking on in-depth assessment. Also, after an in-depth assessment has been completed, audits can be used subsequently to update the assessment reports as new versions of the model are developed.

Procedural Guidelines for Model Assessment

Our experience suggests that the following guidelines would assist in carrying out the assessment functions.

Assessor/Modeler Relations -- A formal agreement should be reached defining the relationships between modeler and assessor with regard to,

- resources to support modeler as well as assessor,
- extent and nature of modeler/assessor interactions,
- confidentiality of intermediate results,
- opportunity for modeler response, and
- post-assessment activities.

Potential Model Applications -- A wide-ranging list of potential applications of the model, incorporating suggestions from all interested parties, should be drawn up at an early stage to provide an explicit policy context for the assessment.

Definition of a Standard Model -- A standard version of a model must be agreed upon and "locked up" prior to the start of experimental analysis. It is desirable, however, to permit changes to be made during early stages of the assessment, particularly if the changes are to correct errors uncovered in the overview assessment.

Assessors as Modelers -- Assessors can and should suggest ways in which the model can be improved, but they should not themselves implement the improvements. To do so would compromise the integrity of the assessment process and would put the assessors in competition with the modelers.

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CHAPTER 1

THE MODEL ASSESSMENT PROCESS

1.1 Introduction

In recent years, policy analysis models have become increasingly important in the policy research process. This development is the result of simultaneous interaction of several factors, including most importantly: the desire of researchers in various disciplines to extend research results to the process of policy research and analysis; the perception of those concerned with policy formulation and analysis that formal models can in fact contribute significantly and positively to the policy research process; and the availability of large-scale computational systems that have the capability to implement complex policy models for timely and efficient use in the policy research process. Energy policy models have been developed or sponsored by government agencies including, most prominently, the National Science Foundation (NSF), the Department of Energy (DOE), and the Environmental Protection Agency (EPA); by industry; and by research organizations, most prominently, EPRI.

While energy policy models are playing an increasingly important role in support of public and private energy policy analysis and decision making, we believe that the potential contribution has not yet been fully realized. This is true for several reasons. First, the expectations of those sponsoring development of policy models may not correspond to reality. Second, modelers may lose sight of the policy issues comprising the subject of research as contrasted with the technical aspects of the underlying reality being modeled. Third, the need for organizational devices that facilitate communication between modelers and model users in both the model development and policy research process may not be realized. Finally, procedures for model review and assessment may not be sufficient to satisfy model users, or those affected by model-based policy analysis, that the model provides a valid representation of the processes being modeled, and that the model's actual implementation has been verified.*

The importance of this last issue in establishing model credibility can perhaps best be illustrated by considering the example of the Project Independence Evaluation System (PIES), a system of energy models developed by the Federal Energy Administration (FEA). Concern by Congress that these important models were not well documented and understood led to legislation in the Energy Conservation and Production Act of 1976 that required documentation and access to the model be improved, that energy data development and analysis activities be separated from policy analysis and decision making, and that established procedures for an independent annual audit of these activities.**

The first independent audit report provides a dramatic statement of issues seen as compromising the credibility of the models comprising PIES:

> ...the credibility of OEIA's [now Energy Information Administration] models has not been established because documentation, verification,

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*An excellent discussion of policy models and the policy research process is provided in [24].

**Congress created a Professional Audit Review Team (PART) consisting of representatives from seven agencies other than DOE to prepare an annual audit report for Congress. The first report was published in December 1977 [39].

> and validation have been neglected. Furthermore, publications describing the current models are scarce, and procedures for public access to them are almost nonexistent. As a result, it is practically impossible for interested parties outside FEA to know whether OEIA's current models have been constructed properly and used correctly and thus, whether OEIA's analytical products and forecast can be used with confidence [39].

The report also questions EIA's procedures in modifying the basic assumptions and structure of the PIES model in response to particular policy analysis problems, and makes a number of recommendations to rectify these inadequacies, including improved documentation (both of model structure and empirical implementation), better control over model changes, validation of model structure, verification of model implementation, sensitivity testing to increase understanding of model response to changes in data inputs, and increased public participation of researchers from outside FEA in professional review. The PART analysis and suggestions are generally consistent with good scientific practice and represent a reasonable standard for ensuring internal control and management of model development, as well as external communication to establish and maintain model credibility.

Other organizations have been actively concerned with increasing understanding and credibility of important energy models. Most prominently, EPRI has sponsored:

- assessments of technical energy models of special interest and importance to the electric power sector [11,17];
- the EPRI-Stanford Energy Modeling Forum as an organizational initiative to facilitate user understanding of models appropriate for selected policy research issues, and to provide for modeler-analyst interactions in the policy research process [16,19]; and
- the M.I.T. Model Assessment Group, an experiment in alternative approaches to independent model assessment, and the subject of this report.

The role of independent assessment of policy models as an element in the policy research process has been discussed by, among others, Gass [22], and Greenberger, Crenson, and Crissey [24]. Gass [23] has proposed guidelines for the assessment process. The present project originated in a recommendation by Greenberger, Crenson, and Crissey ([24], p. 339) who argue that of all the current problems and obstacles to policy models realizing their full potential, the most serious is the lack of researchers and groups professionally committed to independent assessment. Attention to the operational elements and objectives of an independent assessment group were also discussed at the EPRI-Stanford <u>Workshop for Considering a Forum for the Analysis of Energy Options Through the Use of Models</u>, where independent assessment was proposed as a complementary activity to the Forum. Quoting from that report:

> The panel described the role of third-party model analysis as a complement to the Forum studies. The Forum must exploit the backroom concept of Forum operations, relying on the model developers to implement and translate the scenario specifications. The significant practical advantages of the procedure are achieved at the loss of the advantage of constructive independent investigation of model structure and operation. This activity supports the objectives of the Forum effort, but requires a different environment with intense involvement of individual analysts. The contributions of third party assessment can be pursued independently ([19], p. II-19).

The M.I.T./EPRI Independent Model Assessment Project* is an outgrowth of concerns expressed at the Stanford/EPRI Forum Workshop [19].

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*Strictly speaking, the project was originally a collaboration involving the M.I.T. Energy Laboratory and the Computer Research Center for Economics and Management Science of the National Bureau of Economic Research, Inc. Subsequently the Center became part of the M.I.T. Sloan School of Management, so the project is now solely an M.I.T. effort.

The discussions begun at the Workshop were continued between representatives from M.I.T. and the EPRI Energy Analysis and Environment Division. Issues considered included:

- The distinguishing features of independent assessment and the extent to which sponsor and peer review satisfy the need for independent assessment;
- Possible approaches to independent assessment and to organizing such assessments;
- The need to separate the independent assessment process from the research activities of the participants; and
- Formalization of the relationships between the modelers, the assessing group, the sponsors of the assessment, and the users of the model.

Subsequent to these discussions, M.I.T. proposed to EPRI a one-year project to consider these issues in greater detail and to undertake assessments of selected models. The models to be assessed were the Baughman-Joskow Regionalized Electricity Model (REM) and the Wharton Annual Energy Model (WAEM). Two approaches to independent assessment, overview and in-depth, were proposed.* Both approaches were to be applied to REM, while an overview assessment was proposed for WAEM.

The remainder of this chapter discusses the issues that arose in organizing and conducting assessments of REM and WAEM, and presents a framework for policy model assessment based on an analysis of our experience in this project. Chapters 2 and 3 present the structure and assessment of the REM, with the modelers' evaluation of the assessment presented in Chapter 4. The WAEM assessment is presented in Chapter 5.

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*See Sections 1.2.6 and 1.3 for further discussion of these approaches.

1.2 Issues in Model Assessment: Analysis of Two Case Studies

A number of important procedural and substantive issues that arose during the assessment project seems quite likely to recur in later assessment activities. Some of these issues were expected from the outset, but others were unanticipated. Since one major objective of the assessment project was to assist in developing better assessment methodology, it seems worthwhile to describe how these issues arose and to report our approach in dealing with them. The problems are sufficiently complex that our work represents a first approximation rather than a final resolution of the issues. We feel that our experience has, however, provided insights that can be used in future assessment efforts.

1.2.1 Individual vs. Comparative Assessments

Early in the project a concern emerged that assessment of a single model might unjustifiably discredit that model in the eyes of potential model users. Even though the model may be flawed in certain aspects, it may, nonetheless, be the best of the currently available models that can be used for the analysis of a particular set of policy issues. In some instances the flaws may be attributable to deficiencies in the basic underlying data, and thus, common to all of the potentially relevant models. It is just as important to point out the relative strengths of the model as it is to direct attention to its flaws, particularly if these flaws are common to all other models working with the same class of policy issues.

This is a legitimate concern and a potentially serious issue in obtaining modelers' cooperation in the independent assessment process. How will the model assessors obtain modelers' support if modelers cannot be assured that the strengths as well as the weaknesses of their models will be reported together with a discussion of the relative strengths and weaknesses of the potentially competing models?*

In the present case, it has not been possible to provide comparative assessments relating the Baughman-Joskow or Wharton models to other models of the same type. The required resources, including personnel and time as well as funding, would have been substantial and were not available. Nonetheless, we do feel that comparative analysis can play a useful role in the assessment process. In addition to meeting the concerns of modelers, comparative assessment would be of use in establishing the relevance of competing models for particular policy issues and for assisting in the interpretation of different model results in multi-model policy studies [16, 38].

While we believe that the comparative assessment issue is legitimate, we also feel that the concerns expressed by the modelers are in large part symptomatic of the primitive state of independent model assessment. Much of the difficulty is attributable to the lack of well-defined procedures and to the fact that as yet assessment reports are available for only very few models. The problems of modeler cooperation and inappropriate modeler response to model assessment will be greatly reduced when:

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*The issue discussed here was raised on a number of occasions by Professor Martin Baughman.

- o Both modelers and model users come to view independent assessment as a normal part of the process of policy model development;
- o Model sponsors require that independent assessment be planned simultaneously with model development; and,
- o Objectives and procedures of independent model assessment become better defined and understood.

1.2.2 Relations among Assessors, Modelers, and Sponsors

Several important and largely unanticipated issues arose regarding relations between the three principal groups involved in the model assessment process. The contract between the sponsor (EPRI) and the M.I.T. Model Assessment Group spelled out a schedule of activities, deliverables, and financial resources. However, no comparable contract or statement of understanding existed between the Model Assessment Group and the modelers, or between the sponsor and the modelers. It was recognized that the cooperation of the modelers was essential in providing the basic model, together with the necessary documentation, and that the modeler should be involved in project reviews, both to remain aware of project findings and to contribute to an evaluation of the assessment project. However, the need to formalize the relational responsibilities of the three principal groups was not fully appreciated.

Three types of problems arose because of inattention to formalizing assessor/modeler/sponsor relationships. First, the modelers, primarily Professor Baughman, committed significant unreimbursed resources in time and materials to the assessment process. In addition to participating in project review meetings, Baughman devoted significant effort to reviewing and commenting upon draft materials and to the preparation of formal comments on the model assessment (see Chapter 4 of this report). In retrospect, it seems clear that the contract between EPRI and the M.I.T. Model Assessment Group should either have been extended to include resources to cover the cost of modeler participation, or that a separate agreement between EPRI and the modelers should have been negotiated. Such an agreement should include a statement of the terms and conditions for modelers' participation, such details of modelers' deliverables as can be known in advance, and resources to support modeler participation in the assessment process. This approach was possible in the assessment of the Wharton Model because of separate contractual relations between EPRI and Wharton and worked quite well. It was particularly tractable because the Wharton assessment analysis fit naturally into, and indeed contributed directly to, the model development process.

Second, a formal agreement regarding the processing, distribution, and review of draft assessment materials would have helped to mitigate some of the modelers' concerns. It is important that preliminary materials remain confidential until completed by the assessment group, and reviewed by the modeler and sponsor. During the REM assessment process, preliminary material was prepared that hypothesized problems and lapses in the model formulation, implementation, and application. Subsequently, these hypotheses were investigated in detail; some were found to represent misunderstandings on the part of the assessment group; others turned out to be true but relatively unimportant; still others were confirmed to be serious problems. Preliminary communication of hypothesized problems and/or preliminary results to potential users of the model could result in unjustifiable damage to the model's credibility. Although the informal procedure used in the current project did adequately preserve the confidentiality of draft materials, we are now convinced that it is the responsibility of the assessment group to ensure that formal procedures are negotiated and implemented that minimize such risks.

Third, there is the question of appropriate degree of interaction between the assessment group and the modeler. Clearly the assessment group must be able to ask questions of the modeler. In this way lapses in the documentation can be inexpensively corrected without assuming major importance in the final assessment report. Likewise areas of misunderstanding and disagreement can be reduced. The extent of such interactions, however, must be carefully controlled. The assessors must guard against becoming involved in the model research as contrasted with objectively assessing a standard version of a given model.

1.2.3 Defining the Scope of Model Applicability

A model's validity or usefulness is assessed in the context of the particular set of policy issues to which it might be applied. An assessment report should contain an explicit list of the policy applications that the assessors used in judging the adequacy of the model's performance. This list should include all existing and potential applications of the model. Potential applications are especially important since a major objective of model assessment is to provide prospective users of the model with information concerning the model's present and potential capabilities. Knowledge of applications that are possible through relatively inexpensive model extension is important to a prospective user in gaining understanding of the model. This means that the list of applications should, to the extent feasible, include potential future uses of the model as well as existing applications. Thus, in compiling the list, it is better to err on the side of making it too broad rather than too narrow.

The problem with this approach is that the modelers can (and did) point out that the model is being criticized for not doing things it was never designed to do. The list of potential applications may well include issues that the modeler fully recognizes the model is incapable of analyzing adequately. Nonetheless, it is useful to include this information in the assessment report since potential users of the model will be far less well informed than the model builder concerning the limitations on the model's applicability.

In compiling an appropriate list of potential applications, the assessors will, in addition to drawing on their own expertise, need to enter into discussions with representatives of the potential model users, including industry groups, government agencies, and other research organizations. In the present project, this was done through meetings with the Advisory Panel, EPRI, and others. It was also deemed appropriate to include the model builders in some of these discussions. The assessment report distinguishes the potential applications from those for which examples already exist (see Section 3.6).

1.2.4 Assessing a Moving Target

Policy models being used in policy research tend to always be evolving both to incorporate new research results and data and to accommodate new policy research applications. This fact complicates the choice of a standard version of the model for assessment, and raises questions about the treatment of changes in the model once a standard version of the model has been selected for assessment.

When the REM assessment was initiated, it was agreed by all concerned that the currently available version of the model would be "locked up" as the standard model for assessment analysis. This procedure was implemented by obtaining the appropriate computer code and documentation from the modelers. During the course of the overview assessment, however, an analysis of the computer code uncovered what appeared to be several errors in the computer programs. Some of these errors were readily identifiable as flaws in the logic by which the data manipulations were carried out. In other instances, however, the computer code was logical, but the implied behavior patterns were different from those described in the documentation. There was no way to know whether the discrepancy was due to an error in the computer code or in the documentation.

To clarify this issue, it was decided to communicate these preliminary findings concerning "bugs" in the computer code to Professor Baughman. At the June 21-22, 1977 project review meeting Baughman indicated that he agreed with many of the points raised and, as a result, code corrections had been made to the version of the REM being maintained at the Center for Energy Studies at the University of Texas. He recommended that the Model Assessment Group switch to the updated version of REM as the standard model for assessment purposes. His recommendation was accepted.

In retrospect, the process just described raises questions about the appropriateness of the Model Assessment Group's influence on a model that was then under active assessment. Should the assessment continued to have used the standard "locked up" version of the model, even though it was known that it contained errors in the computer code, some of which had significant influence on the model's behavior? Also, there were further problems in that Baughman later expressed concern that the group was still not assessing the most current version of the model.* As a result of his continuing work with the model, he had made additional improvements that he felt should be incorporated in the version of the model used for the assessment. This recommendation for making a second set of changes in the standard model was not accepted.

Anyone who has worked with a model knows that any model that is actively used for policy analysis undergoes a virtually continuous process of change. Modifications and improvements are made as a result of each new application. Assessing a policy model is always going to involve an attempt to hit a moving target. In practical terms, the question is to identify a standard version of the model, the assessment of which will be valuable even while recognizing that some changes are

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*This issue was discussed via a conference call between members of the Model Assessment Group, Dr. Richard Richels, Professors Martin Baughman and Martin Greenberger, and Mr. Dilip Kamat, on January 12, 1978.

likely to have been made by the time the assessment is completed. Providing the modeler an opportunity to append comments to the assessment report is one way to prevent the potential user from being confused.

1.2.5 Assessors as Modelers

In the course of carrying out a model assessment, the assessors will necessarily become intimately familiar with the model's structure and behavioral characteristics. When the assessors discover shortcomings in the model, they will often be able to suggest modifications through which the shortcomings might be overcome. Such suggestions can be very helpful and should certainly be included in the assessment report. The issue that arises is whether the assessors should, themselves, introduce the suggested modifications into the model and incorporate the results in the assessment.

Incorporating new insights has always been an important part of the process by which modeling research is advanced. In our opinion, however, it would be difficult and possibly counterproductive to attempt to merge model development into the assessment process. There are at least two serious problems that would arise in such an undertaking. First, by contributing directly to model development, the assessors would raise questions concerning their objectivity. Having assessors responsible for creating even part of the model they are assessing is contrary to the primary intent of <u>independent</u> model assessment.

The second problem is that by engaging in model development, the assessors will, in effect, be putting themselves in competition with the original modelers. What modeler would agree to submit to model assessment if by doing so he thought he would be helping to spawn a new crop of competitors? It would be in the modeler's self-interest to avoid the assessment process entirely or, failing that, to reveal as little as possible about the workings of the model.

For these reasons, we felt that model development should not be incorporated within the assessment process. It is too likely to lead to conflicts of interest and strained relationships between modelers and assessors. Suggestions for improvements should be made in the assessment report, but implementing the modifications is part of the model building, not model assessment.

1.2.6 Assessment Levels

The original conception of the assessment project took the view that there were two distinct approaches to independent assessment: overview and in-depth. The crucial distinction between these approaches was that the in-depth assessment would involve direct hands-on operation of the model by the Assessment Group, while the overview assessment would rely exclusively upon published reports and other readily available documentation. While this classification provided a useful starting point, our experience suggests that it does not provide sufficient discrimination to be of operational use. A number of issues and problems arose during the project suggesting that planning and organizing an assessment project require a richer classification of approaches in order to clarify and communicate objectives.

First, there is a need to recognize that hands-on operation is not the only way to obtain controlled information on model performance. It is also possible for the assessment group to design computational experiments that are then executed by the modeler with the assessor "looking over the shoulder" to observe how the experiment is actually implemented. Such an approach is especially productive in the case of a model undergoing development or major extension, and for which neither documentation nor a standard version of the model are yet available. For example, this was the situation with the Wharton Annual Energy Model. When organizing the overview assessment of this model it became apparent that the model was still under development, that the existing documentation related primarily to model formulation and research results, not to model implementation, and that any assessment was probably of more use to the modelers and the model sponsor than to a potential user. Accordingly, David Kresge, the principal responsible for the Wharton assessment, proposed the concept of independent model audit as an approach to assessment intermediate between overview and in-depth. This approach is discussed and illustrated in Chapter 5.

It also became clear as the REM in-depth assessment progressed that "hands-on operation" of a model may have many different meanings from an assessment perspective. At one extreme, in-depth assessment may mean just exercising a capability to operate the model in experiments to replicate previously published results, or to perform sensitivity experiments to show how changes in selected independent variables and parameters affect the model's dependent variables. At the other extreme, the original plans for in-depth assessment of REM called for relating independent data used in the model to primary data sources; replication of estimated parameters; estimating new structural relations where technical results were questionable, including them in the implemented model, and performing sensitivity analysis to determine if published analytical results might be compromised; verification of computer procedures and codes through analysis and recoding; and replication of unpublished analytical results.

As the REM assessment progressed, it became clear that the original conception of in-depth assessment was inappropriate. Some of the proposed procedures would have entailed costs far greater than the value of the information they would have produced. We, therefore, modified the original rather extreme concept of in-depth assessment to focus upon: (1) verification of computer code; (2) sensitivity analysis of key parameters and input data; (3) sensitivity analysis of selected structural elements; and (4) evaluation of overall model performance.

In general, then, we found that the overview/in-depth classification as originally conceived does not provide meaningful, operational rules for defining each approach to assessment. This has two serious consequences. First, it complicates the discussion of deliverables between the sponsor and the assessors. In this particular case study the problem was avoided by the close interaction between EPRI and M.I.T., and by the fact that EPRI viewed the project as a prototype. Second, and perhaps more seriously, it limits effective planning, making the process very much one of dealing with issues on an ad hoc basis.

Clearly these issues can be dealt with on an ad hoc basis--conditional upon the resources at hand, the inclinations of the assessors, the cooperation of the modelers, and the objectives of the assessment sponsors. However, in the course of this project we increasingly felt the need for a more effective classification of approaches to assessment, and for guidelines within each approach specifying the characteristics of that particular approach. Such classification and guidelines would facilitate negotiation and clarify expectations among sponsors, modelers, and assessors, and would assist in project organization, planning, and execution. In the following section, we suggest a framework, reflecting the experience gained on this project, that we feel represents a first step in this direction.

1.3 Approaches to Model Assessment: A Working Hypothesis

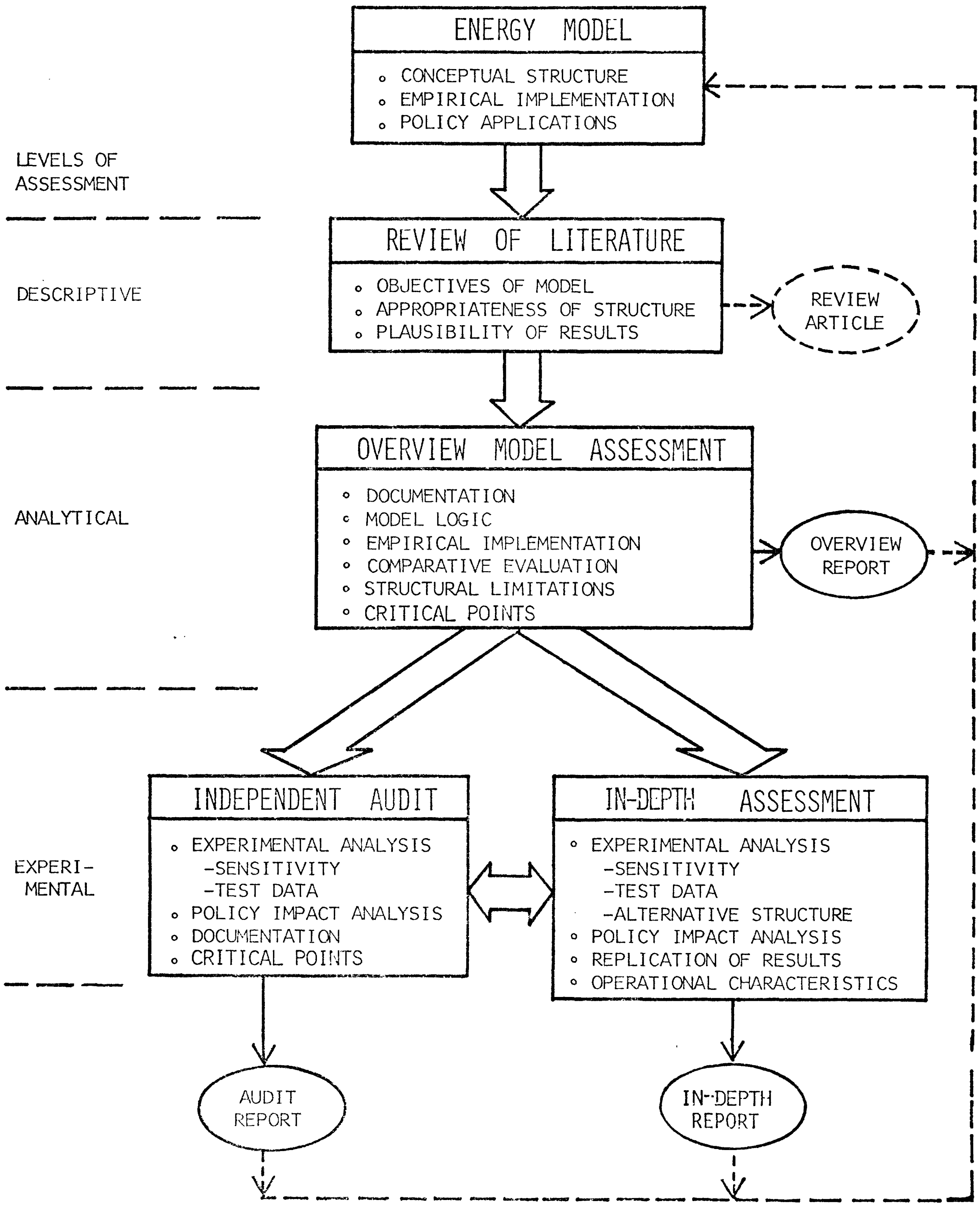
The framework for energy model assessment that we propose as a working (and we hope workable) hypothesis contains four principal elements: (1) review of literature; (2) overview model assessment; (3) independent audit, and (4) in-depth assessment. Although these elements represent four distinct approaches to model assessment, they are most appropriately viewed as the stages in a comprehensive model assessment process. The approaches are interactive and complementary, and should not be viewed as mutually exclusive alternatives.

A summary of the content and relationships among the approaches to energy model assessment is given in Figure 1.1. The assessment process must begin, of course, with an operational version of the energy model to be assessed. For a reasonably mature model, the available documentation should include at a minimum: a concise statement of the model's conceptual structure; a description of the procedures by which the model was empirically implemented (including a discussion of the underlying data bases); and a discussion of the results obtained when the model was applied to an analysis of the policy issues for which it was designed.

For a model still in the development stage, the available documentation would be expected to be more rudimentary, but assessment of such a model is still both feasible and desirable. Indeed, in our opinion, carrying assessment in parallel with model development is one of the most promising avenues for improving the credibility and reliability of energy policy models. The documentation available to such an assessment effort might take the form of working papers that would then

FIGURE 1.1

APPROACHES TO ENERGY MODEL ASSESSMENT



be supplemented through direct discussions with the model builders. Information relating to policy implications might need to be generated as part of the assessment process. Further observations concerning the procedures for assessing a model still in the development stage will be incorporated in the general discussions of assessment approaches.

1.3.1 Review of Literature

An evaluation of a model's structure and characteristics that relies solely on published materials dealing with the model is what we term a "review of literature." Such a review, which is an essential first step in any assessment process, brings together and summarizes the available published information describing the model's objectives, structure, and principal results. As indicated in Figure 1.1, this information is often presented in the form of a review article.

The author of the article will generally try to make some evaluation of the appropriateness of the model's structure for dealing with the policy issues on which it is focused. Often the plausibility of the results will also be judged through comparison with the results produced by other related pieces of analysis. Clearly the evaluative component of the review article depends critically on the expertise of the author and on the completeness of the documentation.

A review of literature is, in our opinion, a useful but essentially descriptive procedure. Published materials discussing the model's structure, implementation, and applications are generally so highly condensed that they do not provide adequate basis for making well-informed judgments concerning the model's validity. A review article is useful to a potential model user in providing a description of what the model is intended to do and of the methodology used to achieve the stated objectives. Such a review article may provide important general information on a model's (or group of models) general applicability. For example, Taylor [40] reviews the major models of electricity demand, comparing the methodology and data structure of each model to a paradigm he establishes. He concludes that none of the existing models reflects the logical structure of the paradigm, and that implementing a new model requires new data development. Taylor's analysis of the literature provides an excellent example of how the model structure and methodology condition the general applicability of a model.

1.3.2 Overview Model Assessment

Overview model assessment, the next stage in the general assessment process, goes beyond literature review by turning to the underlying (and generally unpublished) technical documentation. In our experience, by far the most important element of such documentation is the computer code used to implement the model. In contrast with the published material, a computer code has the very desirable property of leaving nothing to the imagination since every operation must be stated explicitly and unambiguously. Unfortunately, the interpretation of a computer code is often a very difficult task, which may well demand an even higher level of programming skill than was required to build the model in the first place. It is our judgment, however, that analysis of the computer code makes such a significant contribution to an overview assessment that it is, in general, worth the cost entailed. The level of detail and specificity in the assessment is raised significantly when the documentation is augmented to include the computer code and input data. The overview assessment can incorporate precise analysis of the logical structure of the model. Also, the assessment can identify and evaluate the values assigned to each of the empirically estimated parameters in the model.

An overview model assessment report can be expected to contain three major types of information: (1) an evaluation of the empirical content of the model, perhaps with comparison to other empirical studies of similar components; (2) a discussion of the limitations on the model's applicability due to its basic structure; and (3) Identification of the critical points and issues in the model's structure, empirical content, and applications that require further experimental analysis. The comparative evaluation of the empirical content will generally be done on a component-by-component basis, or even on the basis of individual parameters. The purpose is to make more effective use of existing technical expertise in evaluating the model's empirical implementation. When differences do show up, this does not necessarily imply that the model's results are incorrect. It merely indicates that it is a point on which other experts have obtained different results. Depending on how important the point is in the overall model structure, it may also indicate that it is a point on which further analysis is required in later stages of the assessment process.

An overview assessment should include a comprehensive list of policy applications that might be considered by potential users with limited knowledge of the model. Detailed analysis of a model's structure will often show that there are seemingly plausible applications for which the model is actually ill-suited. An overview report should point out these inherent limitations on the model's applicability. This information can assist potential users even when the proposed applications are ones that the modelers have never suggested. The list of potential applications also helps define the context within which the assessment was carried out.

One of the most important features of the overview report is an identification of the model's major "critical points." A critical point for our purposes is defined as an element of the model about which other experts might raise questions and which is expected to have a significant influence on the model's behavior.* A listing of the model's critical points can often serve as a concise summary of the principal findings of the overview assessment. Developing such a list and providing reasons for each item included in the list should be a primary objective of the overview report.

Although an overview report should be able to identify a model's critical points, it will only rarely be able to pass judgment on the adequacy of a model's treatment of them. A critical point is, by definition, an issue on which reasonable, well-informed analysts

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*The term "critical point" is very closely related to the concept of "contention point" and "critical contention point" introduced by Crissey [13]. There are some minor differences in the two concepts, so we chose to use a different phrase to avoid confusion.

disagree. It is, therefore, an issue that cannot be settled by the analytical treatment in an overview assessment. Thus, an overview report is actually an interim document in which many questions are raised but only a few are answered. For this reason, there are many instances in which it may not be appropriate to give wide dissemination to an overview report. Raising a question concerning a model's validity (i.e., identifying a critical point) is not the same thing as proving that the model is invalid. Indeed, later analysis may show that the model's treatment of a critical point is quite adequate and superior to the alternative methodologies. Wide circulation of an overview report may unjustifiably damage the model's credibility. On the other hand, as indicated by the feedback arrow in Figure 1.1, making the overview report available to the modelers and others directly involved in the model's development can contribute significantly to making improvements in the model's structure.

With the completion of an overview report, the purely analytical evaluation of the model has been pushed as far as is feasible. Further assessment of the model's validity requires the acquisition and analysis of experimental data. Such data are essential if the assessment process is to produce substantive conclusions concerning the model's critical points. Although the overview assessment is generally not able to produce such conclusions, it does, by systematically identifying the critical points, provide a sound basis for the next stage of the assessment process.

1.3.3 Independent Audit

An independent audit uses data derived from experiments run with the model to evaluate the model's validity, applicability, and performance. The experiments are designed by the assessors but are implemented by the modelers, with the proviso that a member of the assessment group be present as an observer when the experiments are run. It is our view that this "looking over the shoulder" element of the procedure is essential to the accurate interpretation of the results produced by the experiment. The outcome of an experiment is frequently influenced subtly but critically by the way in which it is implemented.

The audit may use several different types of experiments to explore different aspects of the model's behavior. Arbitrary changes (such as $\pm$ 10 or 20 percent) may be made in key parameters in order to test the model's responsiveness, or sensitivity to such variations. Or, if alternative parameter estimates are available from other studies, these outside estimates may be used in place of the original values in the model. If the parameters were included in the list of critical points for the model, these experiments would help show whether plausible variations in the parameters do, in fact, produce significant changes in the model's results.

An audit may employ test data to compare the model's response pattern with the behavior that would be predicted from theoretical analysis. For this assessment technique to be effective, the test data have to be carefully constructed so that the theoretical predictions are unequivocal. The objective is to design the test so that if the model produces different results from the theoretical predictions, it is clear that there is a flaw in the model's behavior.

Policy impact analysis performs experiments with the model using test data that represent highly simplified versions of relevant policy actions. The interpretation of results is usually a good deal more complex and, hence, more ambiguous than the interpretation of results from simpler test data. The technique is, however, a useful procedure for probing the model's range of policy applicability. If, for example, an experiment produces a result that is qualitatively implausible, it is clear that the model should not be applied to the analysis of the type of policy used in the experiment.

The audit report should use the experimental data together with the analytical material developed in previous stages of the assessment process to provide an evaluation of the model's validity in as many key areas as is feasible. In particular, the report should focus on the model's behavior with regard to its major critical points. The audit report should also provide information on the quality of the available documentation. It is our experience that when a model's behavior differs from what was expected, it is often due to incorrect or unclear documentation. There are also instances in which the documentation is correct, but errors in implementation prevent the model from doing what it is supposed to do. In either case, the report should point out such discrepancies, both to potential users and to modelers.

The information contained in an audit report should be communicated to all those involved in model development since it can assist in making model improvements. Whether the audit report should be disseminated more widely will depend largely on the current stage of model development. If it is a mature model that has been reported in professional publications or has been used in policy applications, then the audit report should also be made generally available. The report should certainly be available to current or potential users of the model. On the other hand, if the model is still in the process of being developed, then the audit report should probably be regarded as an internal working paper. It should be available to the modelers and the sponsors, but should not be more widely distributed.

It should be noted that an independent audit will generally not be able to make definitive judgments concerning all critical points that have been identified. Some points can be investigated only through structural analysis too complex to be handled within the audit approach. On other points, the audit may be able to show that the model behaves in ways that seem inappropriate, but will not be able to show why the model behaves as it does. In these instances, the experimental data generated in the audit are able to push the analysis further than was possible in the overview assessment, but it is not sufficient to make a complete, definitive assessment. For the critical points requiring this more complex type of analysis, it is necessary to proceed to an in-depth assessment.

1.3.4 In-depth Assessment

An in-depth assessment, like an independent audit, relies heavily on the analysis of experimental data. The difference is that the in-depth assessment generates some or all of the data through direct, hands-on operation of the model. Direct operation makes it feasible to carry out much more complex tests, particularly when the tests involve making modifications in the model structure rather than simply changing model parameters or data. Another rationale for the procedure is that the closer one gets to the operation of a model, the more likely one is to identify errors and discrepancies between implementation and documentation.

An in-depth assessment is, as the name implies, an intense, detailed assessment of the model's properties. It is also a relatively costly and time-consuming process. A longer training period is required in order for the assessment group to become sufficiently skilled to operate the model. The more complex experiments will require more careful data preparation; typically, several false starts will be made before an experiment is completed successfully. If the model is large, as is common in the energy field, the experiments may be computationally expensive.

An in-depth assessment can also be conducted at a variety of levels. The assessment can deal with as many or as few of the critical points as seem relevant for the sponsor's purposes. Replication of previous results, including analysis of the underlying data base, is good scientific procedure, but is less than critical for some applications. In-depth assessment is thus an open-ended procedure that can be pressed as far as seems appropriate given the nature of the model, its present stage of development, and its potential uses.

As indicated in Figure 1.1, an in-depth assessment could conceivably be undertaken either immediately after an overview assessment or after an independent audit had first been completed. Because an in-depth assessment is such a substantial undertaking, it is our view that it is usually most efficient to first conduct exploratory analysis through an independent audit. The audit will also allow the assessment group to gain familiarity with the model by working with the modelers before attempting to run the model themselves. Furthermore, in some instances the results of the audit may be so conclusive that it will be decided that there is no need to proceed with the in-depth assessment.

We would expect that an in-depth assessment report would normally be published either in its entirety or in the form of a summary of principal findings. It is unlikely that the assessment process would have proceeded to the level of in-depth analysis unless the model in question were publicly or commercially available and were being used in significant policy analysis. Thus, the results of an in-depth model assessment should be available to those using the model as well as to those potentially affected by model-influenced policy analysis and decisions.

Since any major energy policy model will undergo a virtually continuous process of change, the in-depth report may also be able to contribute to later modifications or extensions in the modeling framework. Unless the modifications are so extensive that they result in a completely new model, the appropriate way to update the assessment would be to use it as the starting point for an independent audit. This is why Figure 1.1 shows an arrow leading from in-depth assessment to audit as well as from audit to in-depth assessment. With the in-depth assessment as the base, the update audit would, of course, focus on those features of the model that had been modified. With so much previous materials and expertise to draw upon, the cost of such an audit would be quite modest and would provide a very efficient means for updating the assessment reports as new versions of the model are developed.

1.4 Procedural Guidelines for Model Assessment

From our experience in the current project, we feel that future assessment efforts would be facilitated if certain procedural guidelines were established at the outset. Regardless of approach taken, the assessment process can be viewed as encompassing three major types of activity: (1) evaluating the validity of the model's logical and empirical structure for a particular set of policy issues; (2) verifying the accuracy of the implementation of the model; and (3) evaluating the usability of the model, including transferability, flexibility and extensibility, documentation, and operational characteristics.

To more effectively carry out the assessment functions, we propose the following sets of guidelines to deal with potentially troublesome issues in four major areas: (1) assessor/modeler relations; (2) potential model applications; (3) definition of a standard model; and (4) assessors as modelers.

Assessor/Modeler Relations: Direct interactions between assessors and modelers are not essential to the assessment process but can significantly increase productivity both through greater efficiency in learning and by eliminating misunderstandings. The assessment process can be facilitated by formalizing the relationships between the modeler and the assessor (and the sponsor as well) with regard to:

- Resources to support the modeler as well as the assessor;
- Extent and nature of interactions between assessor and modeler;
- Confidentiality of intermediate results;
- Opportunities for modeler response to be included in all assessment publications; and
- Post-assessment activities.

Potential Model Applications: Since a policy model must be assessed in the context of the policies to which it is to be applied, a list of these policies should be drawn up at an early stage in the assessment process. The list should be wide-ranging enough to include plausible future applications as well as existing applications. In compiling the list, the assessors should solicit suggestions from the modelers and representatives of potential model-users, such as industry groups, government agencies, and other researchers.

Definition of a Standard Model: A model in active use undergoes virtually continuous change. Thus, model assessment almost always involves an attempt to hit a moving target. It seems appropriate and feasible to permit changes in the model to be made up to the point where the assessment process begins to generate experimental data. It is particularly desirable to allow changes to be made to correct logical or coding errors discovered in the overview assessment. Once an audit or in-depth assessment has begun, however, the model should be locked up so that all experiments are conducted with a standard version of the model.

Assessors as Modelers: To maintain independent objectivity, it is important that the assessment activity remain separate from the model development process. Assessors can and should use the expertise and insights they have acquired to suggest ways in which the model can be improved. But the assessors should not themselves implement the improvements. To do so would compromise the integrity of the assessment process and would strain asessor/modeler relationships by putting the assessors in competition with the modelers.

CHAPTER 2

STRUCTURE OF THE BAUGHMAN-JOSKOW REGIONALIZED ELECTRICITY MODEL

2.1 Summary of Model Design and Objectives

The Baughman-Joskow Regionalized Electricity Model (REM) represents a unique research and modeling effort. It combines a behavioral model of the demand for electricity and competing fuels with a process engineering approach to determining the supply response, all conditioned by the fact that the industry is regulated. To our knowledge, it is the only modeling effort that combines these three components in a single integrated system. As such, it provides a framework for the analysis of policy-related issues affecting the industry and electric consumers. The following excerpts from some of the published materials discussing the model provide a capsule description of the model's design and objectives.*

> Models of various aspects of the energy industries have proliferated in recent years, mostly in response to the need for better policy analysis and technical assessment capabilities following announced Project Independence initiatives. [The Regionalized Electricity Model] is one of this class.
>
> We view this [model] as an attempt to integrate fully engineering and economic modeling of supply and demand interactions, an approach that we believe to be especially useful for analyzing behavior within energy markets. Previous studies of electricity demand . . . have tended to ignore the supply side of the market, the process for setting electricity rates, and the interrelationships between electricity prices and other fossil fuel prices. In a similar way, studies . . . that have examined electricity supply decisions and fuel utilization have often taken electricity demand and electricity prices as exogenous. The model used in this study simultaneously links supply, demand, pricing, and financial behavior in a single integrated framework merging economic-engineering behavioral

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*These excerpts are from ([9], Chapter 2) and ([33], p. 4).

models, financial models, and econometric models to obtain a richer and more powerful modeling apparatus than has hitherto been available to evaluate the electric utility industry.

The Regionalized Electricity Model is a dynamic model of the electricity market. As such it is composed of quantitative descriptions of both the supply and demand side of the market which interact through the price of electricity. Common to both the supply and demand sides of the market are sets of decision rules that govern the dynamic change. Suppliers choose a mix and amount of production plant -- generation, transmission, and distribution equipment -- to supply reliably, at least cost, electricity needs of their consumers. Consumers choose among a set of energy input possibilities -- coal, oil, natural gas, and electricity -- to meet their functional needs and maximize their personal satisfaction within their budget constraints. In both cases decisions are made based upon a set of stimuli, expectations, and goals. The Regionalized Electricity Model represents the authors' attempt to capture the more important of these rules in a mathematical description. In some cases, the description has been derived from experiencing and viewing the industry's behavior. In other cases, it has been deduced using standard statistical techniques.

The link between the supply and demand sides of the market for electricity is the price of electricity. The price of electricity is computed in REM accounting according to the rate-setting practices of state public utility commissions, [where] the price of electricity is set to yield a predetermined rate of return on the utilities' rate base.

The novelty of the model stems not so much from the way in which any of the individual portions of it are structured, but rather from scope and breadth of consistency maintainable from the integration of submodels of distinct but interrelated elements of the industry. With this interconnection a very robust, yet consistent, analytical device is obtained.

Where the details of specific plant and equipment, load, or geographic characteristics of the service area are important, the Regionalized Electricity Model will be of little use. Issues of regional or national policy are more appropriate to its scale and aggregation.

Perhaps equally important, however, is that while REM does not pretend to be capable of addressing capacity expansion, operating, or pricing decisions for an individual electric utility, it does deal with the same type of information that would be used by the individual utility. The model is, in effect, an aggregate version of the individual utility decision process. In the conduct of policy analyses, this fact gives the model several significant advantages. First, it means that the model is capable of looking at the types of problems and policy options that are appropriate to the electric industry. It also makes it easier to convey the results of the analysis to the decision makers involved. Finally, it means that the model can be validated through comparisons with actual behavior and can be improved by incorporating information provided by members of the electric utility industry.

Some of the key features of REM as indicated in the summary description and supported by the more detailed materials are as follows:

(1) The overriding objective of REM is analysis of policy issues affecting the electric utility industry. The model is intended to assist in the decision-making processes of electricity producers, users, and regulators;

(2) REM is designed to simulate or replicate the behavioral processes observed in the electric utility industry. It is not designed as an optimization model except to the extent that the decision makers themselves follow optimization rules;

(3) REM deals with the supply, demand, and regulatory aspects of the electric utility industry in a simultaneous integrated fashion; and

(4) REM operates on a regional level of disaggregation; it does not separately address the decision-making processes in the individual electric utilities. A primary function of the regionalization is to improve the model's applicability to national issues.

2.2 Structural Components (Submodels)

The Regionalized Electricity Model (REM) is organized in three major components or submodels, including the demand, supply, and financial/regulatory submodels. In this section we describe the organization of each of the submodels and their linkage. In the following section we discuss the behavioral decision processes simulated within each component. Figure 2.1 provides a schematic overview of the structural components of REM, the linkages among submodels, and the major exogenous variables required to operate the model.

2.2.1 Demand submodel

The function of the demand submodel is to estimate the amount of electricity demanded in the current time period. Demands for electricity and competing fuels are broken into two major user categories, residential/commercial and industrial, since each consuming sector has different behavioral characteristics, and because the demand for electricity by each sector imposes different requirements on the supply system, particularly regarding transmission and distribution facilities. Demands for electricity and directly competing fuels are estimated for each consuming sector by state.

2.2.2 Supply submodel

The supply submodel, which the authors describe as "the heart of the model," is organized into the following subcomponents: electricity generation, generation expansion, transmission and distribution, load

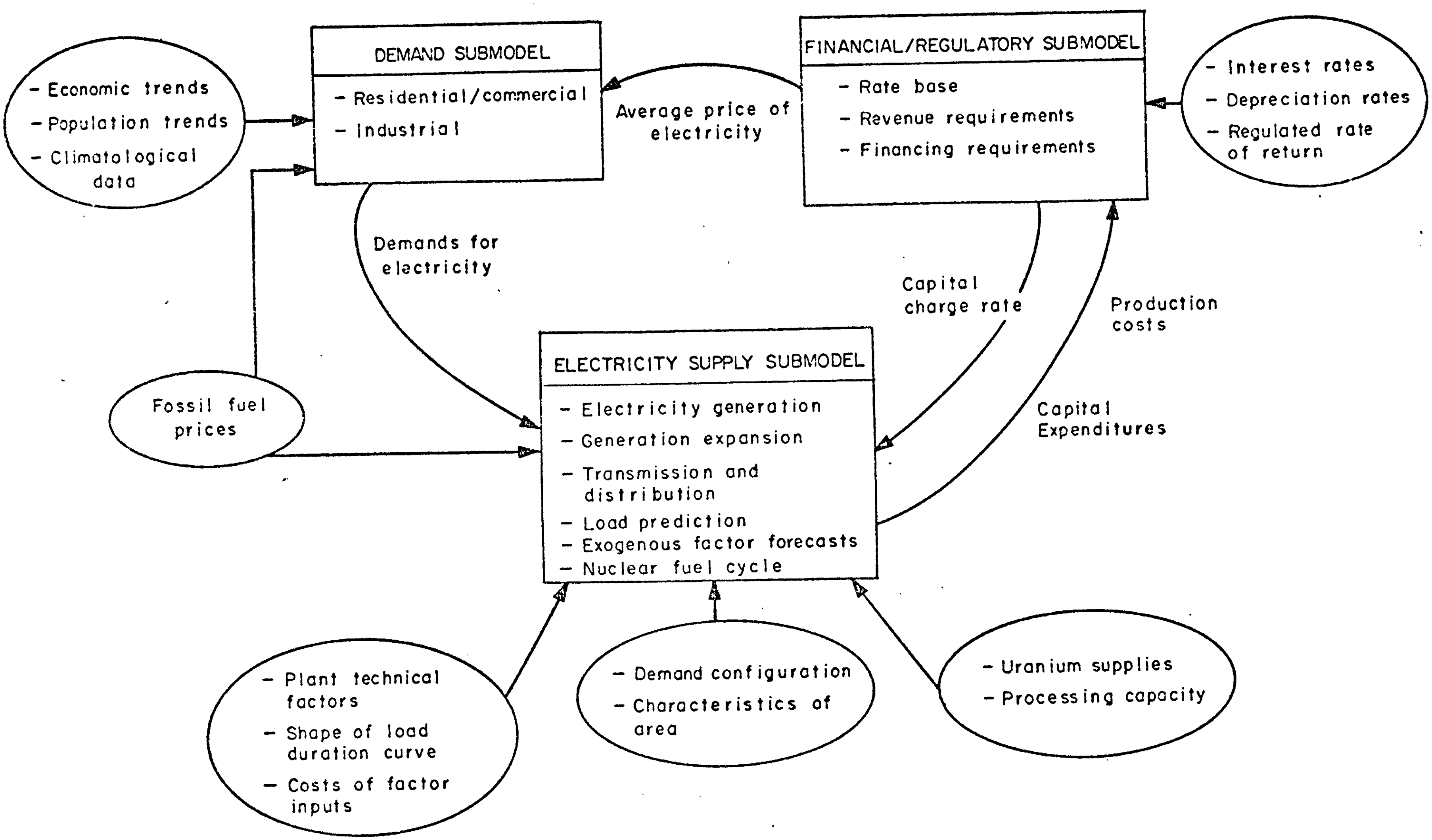


FIGURE 2.1 SCHEMATIC OVERVIEW OF THE STRUCTURE OF THE BAUGHMAN-JOSKOW MODEL

prediction, exogenous factor forecasts, and nuclear fuel cycle. The electricity generation component determines the mix of existing generating plants to be utilized in meeting the current demands for electricity. Outputs of this submodel include a simulated usage rate for each type of plant in each region, production costs incurred in meeting current electricity demands, and an estimate of the fuel requirements of the electric utility industry.

The generation expansion component estimates the capital investments that will be committed in the current period in order to have new capacity on-line in time to meet the expected future demands for electricity. Investment is disaggregated by nine plant types, including oil, gas, coal, LWR-uranium fuel cycle, LWR-plutonium fuel cycle, HTGR, LMFBR, turbines, and hydro. The model explicitly recognizes that each plant type has a different construction lead time.

The transmission and distribution component of the electricity supply submodel estimates the current costs of transmission and distribution, which are included within the estimate of total operation and maintenance costs. Also, this component estimates the amount of investment required to maintain and to expand the transmission and distribution system in response to increased demand.

The load prediction, exogenous factor forecasts, and nuclear fuel cycle modules provide key inputs to other components of the supply submodel, primarily the generation expansion component. The load prediction module simulates the process by which electric utilities forecast the level and configuration of future demands for electricity. The forecasting module performs the same function for the exogenous factors used in the planning process. For example, it determines the fuel prices that electric utilities expect to pay in future years. Although the nuclear fuel cycle component of REM is quite complex, its basic function is to provide estimates of the supply curves for the various types of nuclear fuels, and to ensure that the mass balance accounting of the various nuclear fuel cycles are satisfied.

2.2.3 Financial/regulatory submodel

The financial component of this submodel simulates the process by which the electric industry raises the funds necessary to finance investment in new plant and equipment. On the basis of the amount and composition of the financing required, the model then estimates the financial costs incurred. Financing charges are, of course, one of the important costs of doing business in the electric utility industry.

The principal function of the regulatory component of the submodel is to determine the price charged for electricity. By including a regulatory component, REM explicitly recognizes that the price of electricity is not set in competitive markets, but is determined by the administrative procedures of state public utility commissions and other regulatory agencies.

2.2.4 Information flows

The four principal linkages among the REM submodels are indicated by the curved arrows in Figure 2.1. The demand submodel provides the supply submodel with estimates of the residential/commercial and industrial demands for electricity, the sum of which is the total electricity that must be produced during the current period. Current electricity demand is also an input to the load prediction component of the supply submodel where it is combined with previous demands in forecasting future demands for electricity.

The supply submodel provides the financial/regulatory submodel with two primary inputs, including production costs and current capital expenditures. These cost estimates are used in the financial/regulatory submodel to determine the revenue requirements of electric utilities, and the rate base on which the regulated rate of return is to be calculated. The estimates of capital expenditures are also used to determine the total amount of financing required in the current period. After calculating the total cost of this financing, the financial/regulatory submodel passes back an estimate of the capital charge rate to the supply submodel. This is used in the generation expansion model as one of the factors determining the amount and type of capital investment in future time periods.

Finally, the financial/regulatory submodel determines the price of electricity and passes this on to the demand submodel. It is assumed that the regulatory process uses data from the current period to set the price for the coming period. Reflecting this, the price information that is given to the demand submodel is used to start the REM simulation for the next time period.

In addition to the information flows among submodels, there are a number of important exogenous inputs to REM. Some of the key exogenous factors are outlined in the ovals of Figure 2.1. The demand submodel requires estimates of the trends in future economic activity and population growth as well as certain basic climatological data. Exogenous estimates of fossil fuel prices in future time periods have to be provided to both the demand and supply submodels. In the demand submodel, these prices represent the cost of alternative energy sources. Estimates of alternative fuel costs affect the generation mix and generation expansion decision processes within the supply submodel. The supply submodel also requires exogenous estimates of the technical characteristics of all types of generating plants, including those plants that are not expected to become available until some point in the future. Although the level of demand is estimated by the demand submodel, the shape of the load duration curve is exogenously specified. Fuel costs have already been mentioned, and the cost of other factors of production also have to be exogenously specified.

Exogenous information concerning the geographic and demographic characteristics by region is needed to calculate the equipment requirements and operating costs of the transmission and distribution system. The final set of exogenous inputs to the supply submodel include the basic resource data needed in the nuclear fuel cycle component to derive estimates of the supply curves for nuclear fuels.

The financial/regulatory submodel requires exogenous estimates of interest rates on the different types of financing instruments in all future time periods, including depreciation rates, interest rates, limits on the extent of the different financial instruments consistent with prudent management, and the regulated rate of return.

2.3 Behavioral Processes

The previous section defined the structural submodels of REM, indicating how these submodels are linked together. The purpose of this section is to identify the major behavioral processes within the various submodels that give REM its operating characteristics. These processes will be examined in terms of three major categories of decision makers affecting the electric utility industry, including users of electricity, electric utilities, and regulatory commissions. Table 2.1 provides a summary outline of the key decision processes in REM and of the factors that are primarily responsible for determining the outcome of each process.

2.3.1 Users of electricity

REM treats the demand for electricity as the result of decisions of two major user classes, residential/commercial and industrial. Residential/commercial demands for electricity are determined as a two-stage process. First, total demand for energy of all types is determined as a function of income, population, temperature, and the average price of energy. Then the demand for electricity is calculated using "fuel split" equations, which show the proportion of the total demand for energy that is satisfied by gas, oil, and electricity. Fuel split decisions are determined primarily by the relative prices of various fuels. The decision process in the residential/commerical sector

Table 2.1

Behavioral Processes in REM

Users of Electricity

Decisions or Actions	Elements in Process	Major Factors Determining Outcome
Residential/commercial purchases of electricity	1. Total demand for energy	1.a) Income b) Population c) Temperatures d) Population density e) Average price of energy
	2. Fuel split	2.a) Price of electricity b) Price of other fuels c) Temperatures
Industrial purchases of electricity	1. Total demand for energy	1.a) Value added b) Price of capital c) Average price of energy
	2. Regional distribution of demands	2.a) Population distribution b) Regional energy prices
	3. Fuel split	3.a) Price of electricity b) Price of other fuels

Table 2.1 (cont.)

Behavioral Processes in REM

Electric Utilities

Decision or Actions	Elements in Process	Major Factors Determining Outcomes
Choice of generating plants to meet current demands	1. Availability of generating capacity	1.a) Past investments b) Duty cycle c) Availability factor
	2. Operating and maintenance costs	2.a) Plant technical characteristics b) Factor costs
	3. Load	3.a) Level of demand b) Shape of load duration curve
Investment in new generating capacity	1. Projected load duration curve	1.a) Load prediction b) Shape of load duration curve
	2. Optimal mix of generating plants	2.a) Capital costs b) Operation and maintenance costs c) Fuel costs d) Heat rates e) Utilization factors
	3. Capacity commitments	3.a) Existing capacity b) Optimal capacity c) Lead times

Table 2.1 (cont.)

Behavioral Processes in REM

Electric Utilities (cont.)

Decision or Actions	Elements in Process	Major Factors Determining Outcomes
Expenditures for T and D operation and maintenance	1. Transmission, O and M costs	1.a) Number of residential/commercial customers b) Residential/commercial demand c) Industrial demand
	2. Distribution, O and M costs	2.a) Number of residential/commercial customers b) Number of industrial customers
	3. General overhead costs	3.a) Number of residential/commercial customers b) Number of industrial customers
Investment in T and D	1. Transmission equipment	1.a) Residential/commercial demand b) Industrial demand c) Load density d) Geographic area
	2. Distribution equipment	2.a) Residential/commercial demand b) Industrial demand c) Load density d) Geographic area e) Number of customers

Table 2.1 (cont.)

Behavioral Processes in REM

Electric Utilities (cont.)

Decision or Actions	Elements in Process	Major Factors Determining Outcomes
Mix or financing instruments	1. Total financing requirements	1.a) Capital investments
	2. External financing requirements	2.a) Earnings b) Interest payments c) Dividends
	3. Debt	3.a) Interest coverage b) Debt/asset ratio
	4. Preferred stock	4.a) Preferred stock/asset ratio
	5. Equity	5.a) Projected earnings b) Stock price/earnings ratio
	6. SPA financing	6.a) Residual source of funds

Regulatory Commissions

Decision or Actions	Elements in Process	Major Factors Determining Outcomes
Price of electricity	1. Rate base	1.a) Capital investments b) Depreciation
	2. Rate of return	2.a) Cost of capital b) Allowed rate of return on equity
	3. Revenue requirements	3.a) Operating expenses b) Return to capital

is represented on a state-wide basis, so regionalization is essentially built into the input data. All of the input data, with the exception of the price of electricity itself, is exogenous to REM.

The decisions governing the industrial purchases of elecricity are represented as a three-stage process. First, the aggregate (national) industrial demand for energy of all types is estimated as a function of U.S. economic activity, the price of energy, manufacturing value added, and the price of capital. This national demand is then allocated to states on the basis of population distribution and relative prices of energy in the different states. Finally, fuel split equations involving relative fuel prices are used to represent the choice among different types of fuels. As in the residential/commercial sector, the price of electricity is the only determining factor that is responsive to the REM simulation results.

The demand decisions for both classes of users are treated on an aggregated basis, and the relationships used in REM are derived from historical data. An underlying optimization behavior on the part of consumers and producers is incorporated implicitly only. The demand relationships in REM represent average behavior patterns, which are the net result of a large number of individual decisions.

2.3.2 Electric utilities

Given the current demand for electricity, an electric utility has to decide which combination of the available plants should be used to meet this load. In REM it is assumed that this decision will be made so as to meet the demand at minimum cost. Usage rates for each of the available generating plants will be set so plants with low operating and maintenance costs will be used most intensively and the high cost plants will be used least, or possibly not at all.

The decisions governing the amount to invest in new generating capacity are also based, at least in part, on the assumption of optimizing behavior. It is assumed that electric utilities make a projection of the load duration curve for a specified planning horizon, and then determine the optimal mix of generating plants that would be used to meet the projected load. The optimization procedure will incorporate information concerning the technical characteristics and capital costs of the various types of plants and projected fuel costs, as well as the projection of the load duration curve. The final step in the decision process is simulated by comparing the optimal mix of generating plants, over the relevant planning horizons, with the mix that would occur in the absence of further investments. REM then uses differences between these two capacity projections to determine the capacity investments by plant type during the current time period.

Expenditures for the operation and maintenance of the transmission and distribution (T&D) system are not treated as the result of an explicit decision process in REM, but instead are estimated as necessary costs of doing business. T&D costs are determined by the number of customers and by the amount of electricity being produced. There are no decision variables that can be controlled by electric utilities to alter T&D costs, nor do these costs depend on the type of generating plants being used to produce the electricity.

Investment in T&D equipment is also deterministically projected on the basis of factors such as the level of demand, number of customers, load density, and geographic area. Again, the process is not treated as involving a decision on the part of the electric utilities, since none of the determining factors are under the control of the utilities. The amount of T&D equipment required is not influenced by the type of generating plants being utilized, so the capital expansion plans of the utilities are not affected by the associated amount of T&D investment, except to the extent that these investments increase the total amount of financing required.

The authors give the following description of the method by which REM simulates the decision process governing the financing of new plant and equipment expenditures:

> The various financing alternatives that are made available in the model are long-term debt, preferred stock, common stock, and a hypothetical source called the State Power Authority (SPA). The first three sources have limits on the amount of financing each can provide consistent with the "rules of thumb" guidelines of prudent financial management. These limits, which are in effect capital constraints, serve to simulate the capital markets in a naive but structurally consistent manner. A hierarchy of financing options is established. Debt, having the highest priority, followed by preferred stock, common stock, and SPA financing, are resorted to in this order, to meet external funding requirements. SPA financing is considered a "lender of last resort" without a limit on the amount it can finance ([33], p. 16).

The rules of thumb that are used to simulate the decision process are essentially constraints on the amount of funds that can be raised through each type of financing instrument consistent with prudent financial management. Debt, which is the lowest cost source of funds, is constrained by an exogenously specified limit on the debt/asset ratio, and also by the requirement that available revenues be some prespecified multiple of the required interest payment. Preferred stock is also constrained by a limit on the maximum ratio to assets. The limit on equity financing is determined by the availability of earnings, since REM requires that the ratio of earnings to book value of equity not fall below a prespecified level.

Because REM uses deterministic rules to set limits on the financing through debt, preferred stock, and equity, there is no guarantee that the total amount of funds available to utilities will be sufficient to finance the projected investments in plant and equipment. The model deals with this problem by introducing a fictitious State Power Authority (SPA) which, as a lender of last resort, provides residual financing as necessary. As a result, the existence of a financial gap or capital shortage does not directly influence the model's simulation of the financial decision process.

2.3.3 Regulatory commissions

Although the regulatory process is extremely complex, the decision process in REM is essentially intended to accomplish just one objective: to set the price of electricity. This is generally done by setting a price that will yield a "fair rate of return" on an appropriately defined rate base. The complexity in implementing this process comes in defining the rate base and in determining the fair rate of return. The regulatory decision process in REM characterizes the rate base in terms of utility asset holdings, costs of capital, depreciation, tax schedules, and operating costs, providing a convenient framework for adopting different definitions of the rate base. Given a rate base definition and a specified rate of return, the regulatory process is assumed to set the price of electricity so that revenues generated will be sufficient to produce the specified rate of return on equity.

CHAPTER 3

ASSESSMENT OF THE REGIONALIZED ELECTRICITY MODEL: OVERVIEW AND IN-DEPTH ANALYSIS

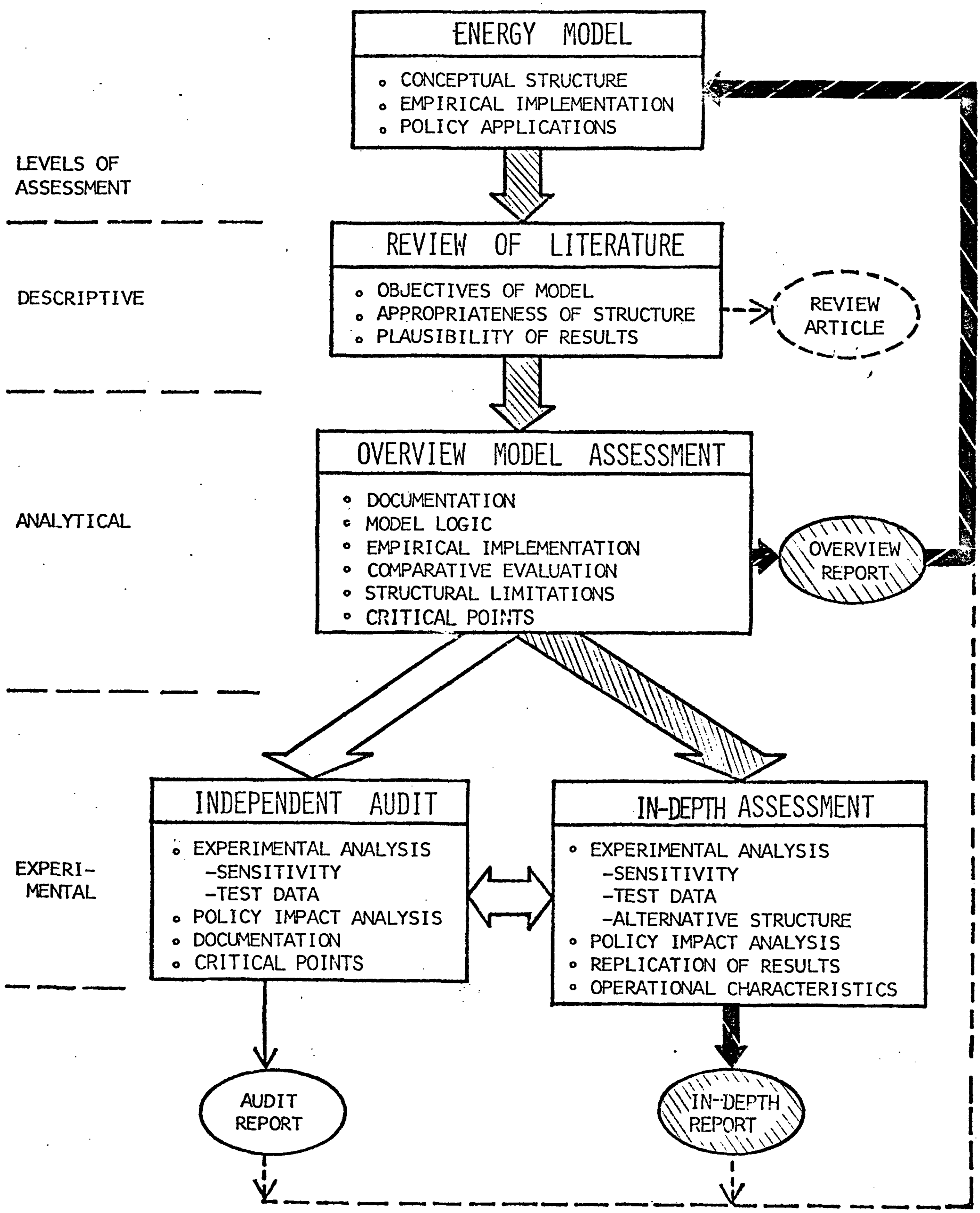
3.1 Outline of the Assessment Procedures

It has become clear during the course of the REM Assessment Project that an overview assessment cannot be restricted to an examination of the available literature. When dealing with a complex model such as REM, that approach would at best result in a concise description of the model's general characteristics and presumed capabilities. Typically the documentation will not contain sufficient information to evaluate either the validity or the range of applicability of the model. The overview assessments presented below rely on a more basic source of information, namely, the computer code used to implement the model. Thus, the overview assessment involves much more intensive analysis than a literature review, but stops short of actually running the model. That task is left to the in-depth assessment which, drawing on the insights gained from the overview evaluation, conducts simulation experiments to test the plausibility and sensitivity of REM response behavior and performance.

The assessment procedures applied to REM and their relationship to the general approach to model assessment are outlined in Figure 3.1. As already pointed out, a review of the literature convinced us that the findings in the overview report would need to rely heavily on analysis of the computer code. The overview report was treated as a confidential working document and was made available only to the assessment group,

FIGURE 3.1

BAUGHMAN-JOSKOW REGIONALIZED ENERGY MODEL ASSESSMENT PROCEDURES



the sponsors, and the modelers, After a review meeting in which Professor Martin Baughman participated, it was agreed that all further analysis would be based on an updated version of the model in which some of the errors identified in the overview report had been corrected. An in-depth assessment was undertaken immediately upon completing the overview assessment. An independent audit was not included in the assessment procedures applied to REM. The results of the in-depth assessment, together with relevant portions of the overview report, are being presented in this report.

The next section of this chapter presents a summary of our observations on the documentation and operating characteristics of REM. The remaining sections deal with our assessment of the substantive aspects of REM. The material to be presented is structured into the same three components or categories as the model itself: demand, supply, and financial/regulatory.

Each section first provides a detailed description of the relevant portion of the model structure. Then the relevant findings from the overview assessment are presented, usually in the form of questions or hypotheses to be analyzed via appropriately designed simulation experiments. These experiments, as well as other sensitivity experiments, are described in each section. The final part of each of the three sections presents the findings of the in-depth assessment as derived from the results of the simulation experiments. The concluding section of the chapter brings together the overview and in-depth assessments, summarizes key findings, and presents some recommendations for possible extensions or improvements in REM.

3.2 Documentation and Operating Characteristics

3.2.1 Documentation

The quality of the documentation for the Baughman-Joskow Regionalized Electricity Model is above average for models of this size and complexity. The available materials provide general descriptions of the model's theoretical structure, empirical methodology, and operating characteristics. A forthcoming book on the model will add to the documentation and value of the model [9]. The chapters we have seen to date (namely, 2, 6, and 7) are well written and illuminate many issues. The authors are candid about how the model performed in early and later experiments, and where constraints have been introduced in order to better track historical data. The documentation is weakest in reporting on the implementation of the model and in providing information to potential users on model use and operations. Also, the quality of the documentation varies significantly among the different components of REM.

The documentation for the demand submodel is excellent, with the basic model structure and empirical derivation summarized in [33]. References [6], [7], and [8] provide more details on the residential/commercial modeling and reference [10] discusses the industrial sector modeling. The documentation of the financial/regulatory model is also quite good [32], [33], [34], and [35]. Reference [35] provides the most thorough derivation of this submodel and reference [34] gives a complete listing of the equations. There are, however, some difficulties in using this latter material since it lists hundreds of equations, using a mixture of acronyms and codes for different parameters. The meaning of each parameter is not self-evident, so a list of symbols is provided for translation, but this entails tedious reference. Also, there are gaps in the definition of concepts in the financial submodel.

It is in the REM supply submodel that major documentation shortcomings appear. For the generation expansion portion of the model, the determination of optimum capacities is reasonably well documented in [34], but the other elements of the planning process are almost totally undocumented. The documentation does not clearly state the underlying assumptions or indicate the degree of caution that a user should take in developing the various input data and interpreting the output. The code implementing the expansion planning component is scattered through several subroutines and is relatively opaque, so it is difficult to determine the logic involved, even after a careful reading of the computer program.

The documentation of the electricity generation component (primarily in [5], [8], and [34]) is also deficient in several areas. In reference [5], the routine is mentioned in just two paragraphs, the second of which deals with the integrated load duration curve, a concept later abandoned. Reference [8] describes the routine more fully, using a series of diagrams that enable the reader to understand in a general way what is going on. There is no research justification for the methdology used and, though it is emphasized that the method produces the lowest cost solution, a comparison with actual utility practice and observed behavior patterns is not given. In general, the documentation does not adequately explain how the supply model parameters have been estimated. Most of the parameter values themselves are not given in the reference materials; they must be extracted from the computer code and data inputs.

In regard to the electricity generation documentation, the following specific points are also worth noting:

- The documentation does not always make clear that the 0.3 percent of total generation supplied by gas turbines in the REM projections is the result of an exogenously imposed constraint, though this procedure is mentioned in [5].
- In order to force the model to track the historical record, a constraint is imposed on the rate at which nuclear facilities can be introduced. The use of this constraint and the need for the user to project it as part of the input data is not made clear in the published materials, although it is in the draft of the forthcoming book [9].

3.2.2 Operating Characteristics

It should be pointed out that it would be extremely difficult to attempt to use REM without the assistance of the model developers. Their insights into the model structure and coding are essential in avoiding pitfalls and interpreting anomalous behavior.

The time required to set up a run of the model and to check through the code to gain assurance that the appropriate change was being made ranged from about five minutes to several hours. The cost per run averaged about $15-20.00 on the M.I.T. system IBM 370/168; almost half of this cost was for printing. The actual CPU time per run averaged about 25 to 30 seconds. The learning process involved in developing sufficient expertise to make structural changes within REM required about 1.5 months of working with the code, the model, and the documentation. This figure assumes that the trainee has excellent knowledge of FORTRAN and electric power systems.

Below are several recommended refinements of the code to assist users:

- The supervisor program should have more comment cards to aid the user; definitions of key variables would be particularly useful;
- A cross-reference list of variable names and all subroutines in which they occur would be useful, because the extensive use of a common pool for storing variables, with minimal calling arguments of the subroutines, makes the code difficult to follow; and
- A series of print switches should be developed so the user has access to a wider variety of output formats without extensive recoding.

3.3 Demand Submodel

3.3.1 Outline of the demand submodel

The demand submodel of REM consists of two major sectors: the residential/commercial sector and the industrial sector. The functional forms for equations and parameter values used are presented in Tables 3.1 and 3.2, respectively. The model of consumer behavior for the residential/commercial sector is summarized as follows:

> The consumer decision-making process is composed of two steps. First, the consumer decides on a level of energy-using services that he desires based on the price of energy, the prices of other goods and services, and household income. This decision defines the expected level of energy that will be consumed. The consumer then seeks to find a combination of fuels that will provide these services most cheaply ([8], p. 306).

The decision model for the industrial sector is separated into three decisions:

> First, . . . given a price of energy, one would expect individual decision makers to choose a mix of energy and non-energy inputs that would minimize the cost of production. The energy requirements would, consequently, depend on the cost of energy relative to costs of other factor inputs and the total output of goods and services. A second, but related level of decision making is the choice of location geographically within the United States . . . . The third and final related decision is the choice of energy form (coal, oil, natural gas, or electricity) to be used ([10], p. 8).

The equations in Tables 3.1 and 3.2 approximate this decision process through a partial adjustment formulation in order to differentiate between the short and long run. For the residential/commercial sector, total state energy consumption per capita is made a function of a weighted energy price (weighted by consumption and end-use efficiency), income per capita, minimum temperature, and population density. Fuel split equations are then used to break out total energy consumption into

Table 3.1

Residential and Commercial Demand Relationships

$$\text{LOG}\left(\frac{\text{ENERGY}}{\text{POPULATION}}\right) = A + B^{*}\left(\frac{\text{PERSONAL INCOME}}{\text{POPULATION}}\right) + C^{*}\,(\text{MINIMUM TEMPERATURE})$$
$$+ D^{*}\left(\frac{\text{POPULATION}}{\text{AREA}}\right) + E^{*}\,(\text{AVERAGE PRICE}) + F^{*}\,\text{LOG}\left(\frac{\text{ENERGY }(-1)}{\text{POPULATION }(-1)}\right)$$

RANGE = 1968 – 1972 $R^2 = 0.927$ $F(5/233) = 622$

COEF	VALUE	T-STAT
A	2.91	5.21
B	2.83e–5	1.77
C	–0.0012	–2.00
D	9.73e–6	2.34
E	–4.83e4	–3.83
F	0.839	26.4

$$\text{LOG}\left(\frac{\text{GAS}}{\text{ELECTRICITY}}\right) = A + C^{*}\,\text{LOG}\left(\frac{\text{GAS PRICE}}{\text{ELECTRICITY PRICE}}\right)$$
$$+ D^{*}\,(\text{MAXIMUM TEMPERATURE})$$
$$+ F^{*}\,(\text{MINIMUM TEMPERATURE}) + H^{*}\,\text{LOG}\left(\frac{\text{GAS }(-1)}{\text{ELECTRICITY }(-1)}\right)$$

$$\text{LOG}\left(\frac{\text{OIL}}{\text{ELECTRICITY}}\right) = B + C^{*}\,\text{LOG}\left(\frac{\text{OIL PRICE}}{\text{ELECTRICITY PRICE}}\right)$$
$$+ E^{*}\,(\text{MAXIMUM TEMPERATURE})$$
$$+ G^{*}\,(\text{MINIMUM TEMPERATURE}) + H^{*}\,\text{LOG}\left(\frac{\text{OIL }(-1)}{\text{ELECTRICITY }(-1)}\right)$$

RANGE = 1968 – 1972 $R^2 = 0.954$ $F(7/482) = 1462$

COEF	VALUE	T-STAT
A	0.07	0.56
B	0.208	1.65
C	–0.137	–3.29
D	–0.0015	–1.04
E	–0.0022	–1.58
F	–0.0022	–1.74
G	–0.0063	–3.19
H	0.897	66.0

Source; [33]

Table 3.2

Industrial Demand Relationships

$$\text{LOG (ENERGY)} = A + B^{*}\ \text{LOG (AVERAGE PRICE)} + C^{*}\ \text{LOG (VALUE ADDED)} + D^{*}\ \text{LOG (PRICE OF CAPITAL SERVICES)}$$

RANGE = 1950 – 1972 R^2 = 0.951   F(3/19) = 182   D.W. = 1.86

COEF	VALUE	T-STAT
A	14.0	4.11
B	–0.239	–1.33
C	0.742	15.08
D	–0.270	–1.89

FIRST-ORDER AUTO CORRELATION COEFFICIENT = 0.337

$$\text{LOG}\left(\frac{\text{ENERGY IN STATE } i}{\text{ENERGY IN CALIF.}}\right) = A^{*}\ \text{LOG}\left(\frac{\text{AVERAGE PRICE IN } i}{\text{AVERAGE PRICE IN CALIF.}}\right) + B^{*}\ \text{LOG}\left(\frac{\text{POPULATION IN } i}{\text{POPULATION IN CALIF.}}\right) + C^{*}\ \text{LOG}\left(\frac{\text{ENERGY (–1) IN } i}{\text{ENERGY (–1) IN CALIF.}}\right)$$

RANGE = 1968 – 1972 R^2 = 0.984   F(2/237) = 7505

COEF	VALUE	T-STAT
A	–0.156	–4.92
B	–0.047	3.24
C	0.927	54.1

$$\text{LOG}\left(\frac{\text{GAS}}{\text{ELECTRICITY}}\right) = A + D^{*}\ \text{LOG}\left(\frac{\text{GAS PRICE}}{\text{ELECTRICITY PRICE}}\right) + E^{*}\ \text{LOG}\left(\frac{\text{GAS (–1)}}{\text{ELECTRICITY (–1)}}\right)$$

$$\text{LOG}\left(\frac{\text{OIL}}{\text{ELECTRICITY}}\right) = B + D^{*}\ \text{LOG}\left(\frac{\text{OIL PRICE}}{\text{ELECTRICITY PRICE}}\right) + E^{*}\ \text{LOG}\left(\frac{\text{OIL (–1)}}{\text{ELECTRICITY (–1)}}\right)$$

$$\text{LOG}\left(\frac{\text{COAL}}{\text{ELECTRICITY}}\right) = C + D^{*}\ \text{LOG}\left(\frac{\text{COAL PRICE}}{\text{ELECTRICITY PRICE}}\right) + E^{*}\ \text{LOG}\left(\frac{\text{COAL (–1)}}{\text{ELECTRICITY (–1)}}\right)$$

RANGE = 1968 – 1972 R^2 = 0.945   F(4/730) = 3130

COEF	VALUE	T-STAT
A	–0.231	–4.31
B	–0.354	–6.80
C	–0.540	–8.23
D	–0.301	–7.13
E	0.856	58.9

Source: [33]

shares represented by gas, oil, and electricity. The binary share equations are functions of the two relevant fuel prices, maximum temperature, and minimum temperature. Pooled time-series cross-section data for 49 states is available for the period 1963-1972. However, the actual estimates are derived from the 1968-1972 subperiod. According to the authors, this sample period generates the most believable results in terms of implied short- and long-term elasticities [8]. One reason for this is that there is not enough variation in the price series over the period 1963-1967. An error components model is used to deal with the pooled data. Instrumental variables are used to avoid inconsistency in the presence of serial correlation and lagged endogenous variables.

For the industrial sector, total national energy demand is specified as a function of an average energy price, value added in manufacturing, and the price of capital services. National data for 1950-1972 are used. Given the total national demand, a second set of locational equations estimates the share of the total energy demand in each state. Conditional logit share equations are used, making a state's share of the national total a function of relative energy costs in each state and relative state populations. A third set of equations then divides total state fuel demand into components of coal, gas, oil, and electricity. A conditional logit formulation is used, making the binary fuel share ratios functions of relative prices in a partial adjustment formulation. Parameters are estimated using pooled cross-section time-series data for the period 1968-72. An error components model is used to correct for the data pooling; and instrumental variables are used, given the presence of lagged endogenous variables.

3.3.2 Overview evaluation

The REM demand submodel generally represents the state of the art in overall energy demand modeling at the time it was constructed. As in the FEA analysis (FEA [21] and Hausman [28]), REM generally utilizes current theoretical and empirical techniques to model the demand for all energy forms on the part of the residential/commercial and industrial sectors, stressing interfuel substitution and explicitly approximating the differences between the short and long runs with a partial adjustment formulation. However, REM does differ in some details from other efforts. For example, it lacks the richness of policy variables and technological specificity found in other interfuel substitution models (Hirst, et al. [29], Cohn, et al. [12], and Lin, et al. [36]). However, these modeling efforts deal only with the residential sector. REM also has less detail than the Anderson [1] and Halvorsen [27] models of residential electricity demand, which, however, deal only with equilibrium electricity demand, ignoring interfuel substitution and the differences between the short and long runs. The partial adjustment residential models of Mount, Chapman, and Tyrell [37] and Houthakker, Verleger, and Sheehan [30] also focus upon electricity demand alone.*

As a general representation of the energy demand situation, the REM demand submodel is effective in meeting its primary objective, which is to make the demand for electricity an endogenous part of the REM modeling system. The demand submodel does, however, have some important

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*Many of these models are compared in greater detail in Charles River Associates [11].

limitations. In particular, it provides little capability for the analysis of policies designed specifically to affect the level and composition of energy demands.

First, the REM submodel is not solved simultaneously with a full energy system model as is done, for example, in the FEA model [21]. As a result, nonmarginal shifts in demand for alternative fuels are not permitted to "play back" upon supply. In essence, supply is assumed infinitely elastic at the exogenously specified price. The failure to deal with such simultaneities could generate serious errors in analyzing the impacts of policies capable of producing major shifts in energy demand patterns. For example, policies aimed at large regional shifts of demand to coal must take into account the potential bottlenecks caused by the limited availability of the transportation infrastructure. Nonmarginal demand shifts to coal could push demand beyond the short-run transportation bottleneck, thereby increasing the short-run supply price. Likewise, nonmarginal shifts in gas demand in New England have historically led to imported LNG from Algeria at a supply price well above that of domestic gas. The assumption of infinitely elastic supply at a constant price ignores these realities and, as a result, may distort projected fuel demands.

Greater disaggregation would be necessary if any conservation policy analysis were to be performed. For example, appliance efficiency taxes, appliance efficiency standards, and heating thermostat controls are use-specific. The incorporation of such policy variables would require a capability to differentiate use-specific price elasticities. Aggregate commercial/residential short-run price elasticities are shown in Table 3.3, while in Table 3.4 price elasticities are presented for the four specific residential uses given in Table 3.3. As is seen in the two tables, disaggregation provides widely different estimates of the relevant elasticities.

For the industrial sector, greater disaggregation, both by manufacturing industries and by functional use, would be extremely useful. Such disaggregation would permit process-specific analysis and the introduction of capital stock characteristics, particularly for fuel-conversion equipment. However, the data problems are substantial and it is not clear that such disaggregation is possible at the moment without significant data development.

In addition to the limitations due to the lack of end-use disaggregation, the conditional logit formulation utilized in the fuel split equations is subject to several shortcomings, including the imposition of constant cross-elasticities, implied mis-specification, excluded variables, and a very restrictive underlying model of individual choices.* Table 3.5 compares elasticity estimates produced by Baughman and Joskow [7]**, Anderson [1], and Lin, Hirst, and Cohn [36]. The conditional logit formulation of REM and Anderson impose constant

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*For a discussion of these issues see Domenich and McFadden [15], Hartman [25], and Hartman and Hollyer [26].

**The demand parameters considered in this earlier study are different from those in REM, but the methodology is similar.

Table 3.3

Aggregate Residential and Commercial Sector

Short-Run Share Elasticities

	Pe	Po	Pg
Se	-0.800	0.284	0.514
So	0.414	-0.929	0.514
Sg	0.414	0.284	-0.698

Source: [8]

Table 3.4

Disaggregated Short-run Fuel Share Elasticities for Particular Residential Uses

HOUSE HEATING

	P_e	P_g	P_o
Electricity	-2.08	2.12	3.30
Gas	.23	-1.48	3.30
Oil	.23	2.12	-7.21

WATER HEATING

	P_e	P_g	P_o
Electricity	-2.08	2.87	2.91
Gas	1.14	-2.28	2.91
Oil	1.14	2.87	-2.74

COOKING FUEL

	P_e	P_g
Electricity	-1.18	1.05
Gas	1.15	-1.03

CLOTHES DRYERS

	P_e	P_g
	-.58	.53
	2.05	-1.99

Source: [6]

Table 3.5

Comparison with Alternative Analyses: Price Elasticities of Fuel Shares in Residential Space Heating

UNCONSTRAINED CROSS ELASTICITIES

	Log-Log			Semi-Log		
	a) Lin, Hirst and Cohn [36]			a) Lin, Hirst and Cohn [36]		
	Pe	Pg	Po	Pe	Pg	Po
Electricity	-2.63	0.44	1.37	-3.19	0.38	1.09
Gas	0.39	-0.57	0.03	0.58	-1.33	0.03
Oil	0.03	3.51	-1.09	-0.15	2.95	-1.01

CONSTRAINED CROSS ELASTICITIES

	b) Anderson [1]			c) Baughman and Joskow [7]		
	Pe	Pg	Po	Pe	Pg	Po
Electricity	-2.04	2.21	0.55	-2.08	2.12	3.30
Gas	0.17	-1.80	0.55	0.23	-1.48	3.30
Oil	0.17	2.21	-1.58	-0.23	2.12	-7.21

cross-elasticities. The Lin, Hirst, and Cohn analysis utilizes a more general logit formulation that avoids the mis-specification (Hartman [25]) and permits the estimation of differential cross-elasticities. As is readily apparent, the elasticity estimates for these studies vary significantly, suggesting that further work is required to reconcile these results before we can place confidence in any of them.*

The applicability of REM is also limited by the fact that the only policy variable currently available to the analyst in the demand submodel is the price of alternative fuels. Even without further disaggregation, there are other policy variables that could have been incorporated; for example, average appliance efficiency, average fuel efficiency, and capital costs of alternative fuel-burning equipment.

Another difficulty is the fact that REM utilizes a single price for electricity resulting in a misspecification of the model, and a formulation that prohibits the direct analysis of peak load pricing. Regarding the misspecification, Taylor [40] has shown that in the presence of a block rate structure, both the average and the marginal price faced by the consumer should be included in the demand equation. If these prices are positively correlated, then omitting one or the other will result in an upward bias in the price elasticity. Since REM employs only the average price of electricity in the demand equation, it follows that its elasticities will be upwardly biased. Taylor provides no

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*For comparability, the elasticities in Tables 3.3 to 3.5 have been based upon a logit specification without a partial adjustment formulation. If a partial adjustment formulation were built into all of them, the pattern of results would still be roughly the same.

indication as to the extent of this bias, although Berndt [3] has shown that on empirical grounds it is insignificant.

The second difficulty with using a single price for electricity is that it rules out the possibility of analyzing within the model the effects upon demand of policies intended to influence the shape of the load duration curve. Most prominently the impact of peak load pricing proposals upon load shape must be analyzed separately. Of course, once their effect on load shape is estimated, the revised load duration curves may be entered into the model and the effects upon generation mix and capacity expansion calculated.

Although the partial adjustment formulation used in REM is an acceptable approximation, it does have some difficulties. In addition to the lack of specificity in dealing with the differences between the short and long runs, the partial adjustment formulation's use of a lagged endogenous variable presents econometric problems. In the presence of serial correlation, potential estimate inconsistencies arise. Furthermore, the lagged adjustment parameter estimate is extremely sensitive. Since the parameter estimated for the lagged endogenous variable is crucial in estimating the difference between short- and long-run responses, these estimated differences will also be quite sensitive to the sample and the assumed stochastic specification.

The basic behavioral assumptions underlying the demand submodel are also subject to question. For both the commercial/residential and industrial sectors, total national demand (for the industrial sector) or state energy demand (for the commercial/residential sector) are estimated first, and these totals are then disaggregated into state demands for particular fuels (gas, oil, coal, or electricity) assuming cost-minimizing behavior on the part of the relevant participant. Such sequential, "trickle-down" decision making implies that consumers decide on the total energy demand independent of their location and of their capital stock and fuel-burning equipment. Once these consumers decide on total energy needs, they decide on location (for industry) and type of fuel to be utilized (for both industry and commerical/residential).

Such assumed decision making may generate believable results at the aggregate residential/commercial sector level. However, at the disaggregated use-specific level, such trickle-down decision making can lead to contradictions. The reason is that consumers will cost minimize in choosing alternative locations and/or fuels <u>in the long run</u> when changes in the stock of capital and fuel-burning equipment are possible. In the short run, relocation and interfuel substitution are nearly impossible. Contradictions can arise when the share equations are applied to total energy demand and the predicted fuel shares imply appliance stock changes that are larger than possible. As a result, the implied direction of causation seems to be the reverse of what actually occurs. Rather than modeling the aggregate and breaking out the components, it would be preferable to undertake explicit micro-modeling of the short- and long-run demands for alternative fuels and equipment and then aggregate the results to produce the totals.

Another difficulty in modeling total industrial energy demand is the treatment of other factors of production entering into the production process. At first, in Baughman and Zerhoot [10], the prices of all other factors of production were ignored. Capital service prices were introduced in Joskow and Baughman [8]. However, they provide no description of the underlying production technology from which the energy demand equation is derived, nor any discussion of the restrictions on technology resulting in the particular equation specification that they estimate. Of particular concern is the simultaneous incorporation of value added (apparently to measure scale effects) with the prices of energy and capital, and the sign of the coefficient for capital service price. If energy and capital inputs are being assumed separable from other factors of production (labor and non-energy intermediate materials and services), the appropriate measure of output is utilized capital, the aggregate of energy and capital inputs. If the utilized capital production function is a two-factor function (energy and capital), then the elasticity of substitution must be positive in order for the isoquants relating the two inputs to be convex. The sign of coefficient C in Table 3.1 indicates that this condition is not satisfied and raises a question as to how to interpret these results.

Furthermore, the national industrial energy demand does not differentiate between the short and long run. Baughman and Zerhoot [10] state that attempts to build in lagged responses were unsuccessful and an Almon lag specification was not attempted because, they claim, it would only worsen multicollinearity compared to unconstrained lag estimation. Actually, the use of the Almon lag should lessen multicollinearity problems. Furthermore, the Koyck lag specification implies an adjustment time of two years, which is too short to be believable. As a result, Baughman and Zerhoot [10] and Joskow and Baughman [33] do not use a lag specification, implying that price response is immediate (i.e., within a year) for aggregate industrial energy demand. That assumption is difficult to accept as an accurate description of the real world process.

3.3.3 Design of the simulation experiments

The overview assessment considered the adequacy of the behavioral and technical structure of the REM demand submodel, the adequacy of its empirical implementation, and its applicability to policy analyses. To summarize, the overview assessment raised questions concerning the adequacy of the basic structure of the REM demand submodel in the following major areas:

- o Differentiation between the short- and long-run determinants of demand;
- o Level of disaggregation of the technical characteristics of the fuel-burning appliance stock;
- o Inclusion of specific policy variables dealing with conservation, regulation, and allocation of energy resources;
- o Treatment of new technologies and consumer responses to them;
- o Behavioral assumptions underlying the model of consumer choice; and
- o Behavioral assumptions underlying the model of production.

Further in-depth analysis of these issues would require significant respecification of the structure of the demand submodel. While it would be desirable at some point to assess the effects of alternative structural forms, that task is outside the scope of the present assessment activity. The in-depth simulation experiments are instead designed to test the model's response to changes in key parameters and exogenous variables that appear in the demand submodel as presently structured. The experiments fall into five categories:

- Relative fuel prices,
- Constraints on fuel supplies,
- FEA price scenarios,
- Proportional fuel price changes, and
- Alternative demand parameters.

Relative Fuel Prices: One of the principal functions of the demand submodel is to estimate how the demand for electricity will respond to changes in the prices of other energy sources. These experiments test the model's sensitivity to changes in the prices of natural gas and oil. They also show how a Btu tax or other energy tax can be introduced into REM and how the model responds.

Constraints on Fuel Supplies: The effect of constraints on energy supplies, via an oil embargo or limitations on supplies of natural gas, is currently a matter of considerable concern. While REM has no provision for directly incorporating such constraints, there is the possibility that they could be proxied by changes in the relevant fuel price. Indeed, Baughman and Joskow use this device to constrain natural gas usage to historical levels. The experiments test the appropriateness of using this indirect approach for analyzing the impacts of future constraints on fuel supplies.

FEA Price Scenarios: As pointed out in the overview, REM is not solved simultaneously with a full energy system model but instead specifies fuel prices exogenously. These experiments use the fuel prices from the FEA Reference Case in place of the prices in the REM data. The purpose is to see how REM results are affected by a set of prices which are, at least in principle, consistent with market clearing in the major energy markets.

Proportional Fuel Price Changes: One of the behavioral assumptions underlying the demand relationship is that the share of total energy demand going to each fuel will be unaffected by proportional changes in the prices of all fuels. These experiments test to see whether this assumption is, in fact, satisfied by the empirical relationships used in REM.

Alternative Demand Parameters: The overview assessment pointed out that changes in theoretical specifications, estimation techniques, or time periods can produce significant changes in the estimated values for key demand parameters such as the share elasticities. These experiments introduce alternative values for industrial demand parameters to see how sensitive REM results are to such changes. This is a rough test of the model's robustness in the face of the errors or uncertainties in the parameter estimates.

3.3.4 In-depth Assessment

The simulation experiments reported here focus on changes to variable values and parameters of the demand submodel. However, the experiments are performed on REM as a whole, so the results measure impacts on the processes represented in the supply and financial/regulatory submodels, as well as in the demand model. The experimental results are generally analyzed by comparing them with the results of the "base case" simulation, as defined by the data supplied by the authors. Therefore, it is useful to begin by giving a brief description of the REM base case projections.

Base Case Results

The REM base case projections to 1995 are summarized in Table 3.6. Total energy demand is projected as remaining relatively constant between 1975 and 1985 and then as increasing at an average rate of 1.8 percent annually between 1985 and 1995. It should be noted that the REM demand estimates do not include energy demands by the electricity producing sector nor transportation demands (which amounted to more than half of national energy demand in 1975). The demand for electricity grows at 4.7 percent annually between 1975 and 1995. Its share of total energy demand reaches 40 percent in 1995, more than double its share in 1975.

For national residential/commercial demands, gas declines absolutely (from 6.68 to 6.23 quads) and as a percent of total residential/commercial demand (from 48 to 39 percent). Residential/commercial electricity demand increases from 3.36 quads (24 percent of total) to 6.31 quads (39 percent) in 1995. The projected industrial demands indicate a 22 percent decline in natural gas consumed, with the share of gas decreasing from 58 percent (1975) to 37 percent (1995). Oil

Table 3.6

REM Base Case Results

U. S. ENERGY DEMANDS* (Quadrillion BTU's)

	1975	1980	1985	1990	1995
RESIDENTIAL/COMMERCIAL					
Total	14.02	13.01	13.06	14.05	15.98
Gas	6.68 (48)	5.87	5.53	5.68	6.23 (39)
Oil	3.98 (28)	3.34	3.14	3.22	3.44 (22)
Electricity	3.36 (24)	3.87	4.38	5.15	6.31 (39)
INDUSTRIAL					
All fuels	16. 10	16.33	17.01	18.30	19 99
Gas	9.33 (58)	8.34	7.89	7.42	7.31 (37)
Oil	1.99 (12)	1.74	1.58	1.53	1.51 (8)
Electricity	2.47 (17)	3.75	5.26	6.70	8.19 (41)
Coal	2.30 (14)	2.00	2.27	2.64	2.98 (15)
Total					
Total	30.12	29.34	30.06	32.34	35.97
Gas	16.02 (53)	14.71	13.42	13.10	13.54 (38)
Oil	5.97 (20)	5.03	4.72	4.75	4.95 (14)
Electricity	5.33	7.55	9.64	11.35	14.50 (40)
Coal	2.30 (8)	2.00	2.27	2.64	2.93 (8)

U.S. ELECTRICITY SUPPLY*

	1975	1980	1985	1990	1995
Installed Generation Capacity (GW)					
Nuclear	43.13 (10)	81.81	140.26	246.90	361.52 (38)
Coal	195.33 (44)	253.48	323.25	398.91	429.82 (45)
Oil and Gas	162.59 (37)	151.96	136.83	119.74	102.12 (11)
I.C.	43.43 (10)	45.34	57.62	57.09	67.09 (7)
Electricity Generation (MMWH)					
Nuclear	276.21 (18)	532.56	898.14	1642.51	2443.09 (58)
Coal	912.50 (58)	1194.31	1427.91	1588.43	1672.61 (40)
Oil and Gas	369.74 (24)	326.52	362.85	125.67	50.78 (1)
I.C.	5.64 (0.3)	15.25	9.42	11.55	14.27 (0.3)
Price of Electricity (mills/Kwh)	26.7	35.2	46.42	60.71	79.58
Total Assets ($billions)	171.04	290.6	501.46	878.29	1414.06

*Shares of totals are shown (in percent) in parentheses.

consumption also declines about 25 percent in absolute terms. Industrial electricity consumption increases considerably to offset the decreases in gas and oil demand, with electricity consumption being 41 percent of 1995 industrial demand. Coal consumption remains fairly stable as a percent of total industrial demand.

The electricity supply projections show a clear shift from oil and gas to nuclear, while the situation with regard to coal is ambiguous. In terms of installed generation capacity, the share attributable to nuclear rises from 10 to 38 percent, the share of oil and gas falls from 37 to 11 percent, and the share of coal remains at about 45 percent. In terms of electricity generation, however, nuclear accounts for 58 percent of the 1995 total, while coal contributes only 40 percent and oil and gas just 1 percent. That is a significant drop from the 58 percent of total electricity generation that coal plants supplied in 1975. The projections for installed capacity and electricity generation taken together imply that the utilization rates for nuclear plants are going to have to rise substantially, relative to the utilization rates for coal plants.

Some obvious questions can be raised concerning the base case results, such as the slow growth in total energy demands and the composition of electricity supply. However, with regard to the primary objective of the demand submodel, which is to project the demand for electricity, the base case results seem fairly reasonable. That is, they provide an adequate starting point for the simulation experiments reported below.

Relative Fuel Prices

One of the functions for which the demand submodel seems best suited is to trace out the impacts of changes in fuel prices. There are many forces that could produce price changes. A particularly interesting one is the possibility of a tax on the use of energy resources. In this experiment, the price of natural gas is increased to reflect a 100 percent tax imposed on the Mcf gas price in 1975. The tax is kept in place throughout the entire period to 1995. The results of the experiment are summarized in the first two columns of Table 3.7

The REM projections differ from the base case results in the expected directions. Total demand for energy declines as a result of the increase in the cost of gas. For both residential/commercial and industrial demands, natural gas usage declines significantly as a share of total fuel demand, while electricity, oil, and coal increase their shares. Electricity demands expand by the largest absolute amounts but, in relative terms, coal and oil also experience substantial gains. The long-run impact is, as would be expected, much larger than the short-run impact. The immediate effect of the gas tax is to reduce the demand for gas in 1975 by 14 percent; in 1995, gas demand is reduced by 57 percent. The impact on industrial demand is particularly pronounced, with the 1995 industrial demand for gas being less than one-third of the base case projection.

Looking at the electricity supply projections, the major effect of the gas tax is to create a need for additional generation capacity to meet the increased demands for electricity. All of this expansion in capacity goes into nuclear and coal plants, since utilities are not

Table 3.7

CHANGES IN FUEL PRICES

	Natural Gas Tax 1975	Natural Gas Tax 1995	Tripling of Gas Price 1975	Tripling of Gas Price 1995	Tripling of Oil Price 1975	Tripling of Oil Price 1995
U. S. ENERGY DEMANDS* (Quadrillion BTU's)						
Residential/Commercial						
Total	13.5	13.4	13.2	12.3	13.6	14.0
Gas	6.1 (45)	3.4 (26)	5.7 (48)	2.3 (19)	6.7 (50)	6.6 (47)
Oil	4.0 (30)	3.6 (27)	4.1 (31)	3.7 (30)	3.4 (25)	1.2 (9)
Electricity	3.4 (25)	6.3 (47)	3.4 (26)	6.3 (25)	3.4 (25)	6.2 (44)
Industrial						
Total	14.6 (100)	17.9	13.7	17.5	15.5	19.8
Gas	7.7 (53)	2.4 (14)	6.8 (57)	1.2 (7)	9.3 (60)	8.2 (41)
Oil	2.0 (14)	2.0 (11)	2.4 (15)	2.2 (13)	1.5 (9)	.2 (1)
Electricity	2.5 (17)	9.5 (53)	2.5 (18)	9.8 (56)	2.5 (16)	8.1 (41)
Coal	2.3 (16)	3.9 (22)	2.3 (17)	4.3 (25)	2.3 (15)	3.4 (17)
Total						
Total	28.1 (100)	31.3	26.9	29.8	29.1	33.8
Gas	13.8 (49)	5.8 (19)	12.5 (47)	3.5 (12)	16.0 (55)	14.8 (44)
Oil	6.1 (22)	5.6 (18)	6.1 (23)	5.9 (20)	4.9 (17)	1.4 (4)
Electricity	6.0 (21)	15.9 (51)	6.0 (22)	16.1 (54)	5.9 (20)	14.3 (42)
Coal	2.3 (8)	3.9 (13)	2.3 (9)	4.3 (15)	2.3 (8)	3.4 (10)
U. S. ELECTRICITY SUPPLY*						
Installed Generation Capacity (GW)						
Total	444.5	1076.7	444.5	1102.3	444.5	959.6
Nuclear	43.1 (10)	387.4 (36)	43.1 (10)	382.0 (35)	43.1 (10)	357.8 (37)
Coal	195.4 (44)	512.8 (48)	195.4 (44)	530.2 (48)	195.4 (44)	427.5 (45)
Oil and Gas	162.6 (37)	102.1 (9)	162.6 (37)	102.1 (9)	162.6 (37)	102.1 (11)
Internal Combustion	43.4 (10)	74.3 (7)	43.4 (10)	88. (8)	43.4 (10)	72.2 (8)
Electricity Genration (MMWH)						
Total	1602.1	4614.9	1610.7	4635.1	1571.0	4102.2
Nuclear	276.2 (17)	2620.3 (57)	276.2 (17)	2478.4 (53)	276.2 (18)	2391.6 (58)
Coal	912.9 (57)	1836.5 (41)	912.9 (57)	2071.7 (44)	912.7 (58)	1620.5 (40)
Oil and Gas	407.2 (25)	92.6 (2)	415.8 (26)	119.1 (3)	376.4 (24)	76.2 (2)
Internal Combustion	5.8 (.3)	15.5 (.3)	15.8 (.4)	15.9 (.3)	5.7 (.4)	13.9 (.3)
Price of Electricity (mills/Kwh)	28.9	80.6	31.0	83.2	28.1	81.9
Total Utility Assets ($ billions)	173.5	1539.5	174.5	1563.2	172.0	1391.8

* Shares of totals shown (in percent) in parentheses

projected as investing in any oil- and gas-fired facilities, either in the base case or in this experiment. The impact on nuclear capacity resulting from the 1975 gas tax does not show up until the 1990's. This is partly due to the ten-year lead time for the construction of nuclear facilities, but it is also due to the long lags involved in the calculation of the expected fuel prices used in the REM capacity expansion planning.

The amount of electricity generated by coal plants increases substantially throughout most of the projection period. In the long run, nuclear plants increase their output, but again this does not occur until after 1990. The electricity supplied by oil and gas units varies erratically depending on the peaking and cycling needs in each year. In all experiments, oil and gas units supply only a small portion of total electricity generation by the late 1980's.

In general, the differences between this experiment and the REM base case seemed consistent with the type of change that was introduced. The experiment also showed that imposing energy taxes or making other changes in fuel prices in REM is conceptually and operationally straightforward.

Constraints on Fuel Supplies

The assessment of supply constraints with REM is not easy, given the structure of the demand submodel and REM as a whole. Since the theoretical and empirical structure is based on the assumption of infinite supplies at an exogenously specified price, limited supply scenarios can only be analyzed indirectly and with difficulty. The model reformulation necessary to assess supply constraints directly would involve introducing submodels for each of the primary energy types and reformulating the model to allow market clearing prices to be determined. This would be a considerable undertaking. An alternative method is to proxy supply constraints through price changes. Thus, the impact of a natural gas cut-off might be approximately assessed by raising the gas price. While this might roughly capture supply unavailability in the share equations, it would bias the demand results because the higher gas price would be rolled into the average energy price used in calculating total energy demand. Total energy demand would not respond in the same way to a direct supply constraint (with regulated prices) as it would to supply constraint, which is proxied through a large increase in fuel prices.

As an experiment to assess the feasibility of using a price increase in REM to approximate the impact of a limitation on the supply of natural gas, the price of natural gas is increased by a factor of three starting in 1975. This experiment is reported in the third and fourth columns of Table 3.7. Then, to proxy the effects of an oil embargo or import quota, another experiment was run in which the price of oil was increased by a factor of three. These results are shown in the last two columns of Table 3.7.

Since these scenarios are similar to the natural gas tax in the previous experiments, the results are expected to be similar but more pronounced. This is indeed the case. When the price of gas is tripled, demand for natural gas drops, with the industrial decline (as a percentage of total) particularly sharp. Electricity and to some extent oil substitute for gas in the residential/commercial sectors, while both of these fuels and coal are the substitutes in the industrial sector. When the oil price is tripled, there is substitution away from oil toward gas and electricity for both residential/commercial and industrial users. Fairly equal shifts toward gas and electricity are projected. Based upon relative prices alone and assuming the availability of the necessary gas, the pattern of these compositional effects seems reasonable.

The problem with using REM in this way is shown by the impact on total energy demands. The limitation on gas supplies reduces total energy demand by three quads (11 percent) in 1975 and by six quads (17 percent) in 1995. This reduction in total energy demand is implausibly large if gas supplies are rationed, while gas prices are kept from rising sufficiently to clear the market. The tripling of oil prices (to proxy an oil embargo) produces similar results though, since oil contributes a smaller share of total energy, the reduction in total energy demand is smaller.

These experiments show that it is not appropriate to use REM to analyze situations where energy supplies are limited while prices are controlled. Such supply limitations need to be entered as direct constraints; they cannot be proxied through price increases.

FEA Price Scenarios

One of the structural difficulties with REM is that the demand and supply submodels are not solved, either simultaneously or iteratively, to obtain market clearing fuel prices. The structure of REM assumes infinitely elastic fuel supplies at these exogenously specified prices. To evaluate the reasonableness of the prices used in REM and to test the sensitivity of the model to widespread price changes, the market clearing FEA solution prices are introduced into REM. The solution prices are for the FEA 1985 Reference Case pegged to imported oil prices of $8, $13, and $16 per barrel (1975 $).* Based upon these prices, three sets of fuel prices are obtained for 1985:

	Case 1	Case 2	Case 3
Imported oil ($/barrel)	8.00	13.00	16.00
Coal ($/ton)	26.47	27.82	28.11
Natural gas ($/MCF)	1.79	2.03	2.07

Using the assumed inflation rate of the base case (5.5%) and the pattern of real price changes over 1975-1995 incorporated in their baseline scenario, these 1985 reference prices are used to develop a series of oil, coal, and gas prices in constant dollars. The price series are developed for all three reference cases. The results of incorporating these fuel price estimates into REM are reported in Table 3.8.

In general, the FEA price solutions for Case 1 yield higher price estimates for coal and natural gas relative to oil than those of Baughman and Joskow. These higher prices reflect the presence of the rising supply curves for coal and gas, which Baughman and Joskow assume away by making all fuel supplies infinitely elastic at the exogenously specified supply prices.

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*See [20], Appendix G. There are, of course, corresponding prices for grades of petroleum products, electricity, etc. in the final solution.

Table 3.8

FEA PRICE SCENARIOS

	Case 1 ($8 Oil) 1975	Case 1 ($8 Oil) 1995	Case 2 ($13 Oil) 1975	Case 2 ($13 Oil) 1995	Case 3 ($16 Oil) 1975	Case 3 ($16 Oil) 1995
U.S. ENERGY DEMANDS* (Quadrillion BTU's)						
Residential/Commercial						
Total	13.9	17.9	13.7	16.0	13.6	15.4
Gas	6.3 (46)	6.6 (37)	6.3 (46)	6.1 (38)	6.3 (46)	6.1 (40)
Oil	4.2 (30)	5.4 (30)	4.1 (29)	3.8 (24)	3.9 (29)	3.2 (21)
Electricity	3.4 (24)	6.0 (33)	3.4 (25)	6.0 (38)	3.4 (25)	6.0 (39)
Industrial						
Total	15.4	21.5	14.9	19.9	14.8	19.6
Gas	8.4 (54)	8.2 (38)	8.1 (54)	7.7 (39)	8.1 (55)	7.8 (40)
Oil	2.3 (15)	4.3 (20)	2.1 (14)	2.1 (10)	2.0 (13)	1.5 (7)
Electricity	2.5 (16)	7.2 (34)	2.5 (17)	8.2 (41)	2.5 (17)	8.4 (43)
Coal	2.2 (14)	1.8 (8)	2.2 (15)	2.0 (10)	2.2 (15)	2.0 (10)
Total All Fuel	29.3	39.4	28.6	35.9	28.4	35.0
Gas	14.7 (50)	14.8 (37)	14.4 (50)	13.8 (39)	14.4 (51)	13.9 (40)
Oil	6.5 (22)	9.7 (25)	6.1 (21)	5.9 (16)	5.4 (21)	4.7 (13)
Electricity	5.9 (20)	13.2 (33)	5.9 (21)	14.2 (40)	6.0 (21)	14.4 (41)
Coal	2.2 (8)	1.8 (5)	2.2 (8)	2.0 (6)	2.2 (8)	2.0 (6)
U.S. ELECTRICITY SUPPLY*						
Installed Generation Capacity GW						
Total	394.4	870.4	374.4	934.5	444.4	851.6
Nuclear	43.1 (12)	408.5 (47)	43.1 (12)	438.7 (47)	43.1 (10)	445.3 (52)
Coal	195.4 (52)	252.1 (29)	195.4 (52)	339.9 (36)	195.3 (44)	247.2 (29)
Oil and Gas	92.5 (25)	157.7 (18)	92.5 (25)	102.3 (11)	162.6 (37)	102.1 (12)
Internal Combustion	43.3 (12)	52.1 (6)	43.3 (12)	53.5 (6)	43.4 (10)	57.0 (7)
Electricity Generation (MMWH)						
Total	157.86	3764.2	1596.9	4083.8	1602.3	4145.6
Nuclear	276.2 (17)	2687.5 (71)	276.2 (17)	3016.8 (74)	276.2 (10)	3059.8 (74)
Coal	906.0 (57)	985.0 (26)	912.9 (57)	1048.0 (26)	912.9 (57)	1059.6 (26)
Oil and Gas	390.7 (25)	78.6 (2)	402.1 (25)	5.1 (0)	407.6 (25)	12.1 (0)
Internal Combustion	5.7 (.4)	13.1 (.3)	5.7 (.4)	13.8 (0)	5.6 (.4)	14.1 (0)
Price of Electricity (mills/Kwh)	27.7	79.4	29.0	79.3	29.4	79.4
Total Utility Assets ($ billions)	171.9	1283.4	173.2	1410.8	173.7	1437.4

*Shares of totals shown (in percent) in parentheses.

With higher gas and coal prices, the REM supply model projects an increase in the price of electricity. As a result, there is a shift in the composition of demand toward oil and away from electricity and coal.

The results in Reference Cases 2 and 3 are interesting in that they are practically identical to the REM base case results. This holds in terms of absolute and compositional demand effects at both regional and national levels, and for both residential/commercial and industrial users. In contrast, the mix of the projected installed capacity and electricity generation in these experiments is quite different from the base case results. Nuclear plants pick up a substantial increase in share, while coal plants decline by an equivalent amount. In both cases, nuclear plants account for about half of 1995 installed capacity and nearly three-fourths of electricity generation. Those shares are much higher than in the REM base case. Coal plants, on the other hand, are shown as generating 37 percent less electricity than in the base case.

The REM response to the FEA price scenarios presents a somewhat confusing picture. The demand results are stable, and seem generally reasonable, but the supply results are volatile. The generation mix in the REM projections is extremely sensitive to changes in the set of fuel prices fed into the model. Changes in fuel prices that have virtually no impact on energy demands can cause drastic shifts in the mix of nuclear and coal plants.

Proportional Fuel Price Changes

The fuel share equations utilized in the demand submodel should exhibit homogeneity of degree zero. That is, if the prices of all fuels are doubled or halved, total fuel demand should change but the shares going to each type of fuel should remain constant. To test the model's response to such price movements, an experiment was executed in which fuel prices used in the state fuel share equations, including the price of electricity, were raised above base case values by 25 percent. In effect, the fuel share equations were detached from the rest of the model and solved for the base case prices, and for these prices scaled by 1.25. This experiment confirmed that the fuel share equations as implemented exhibit zero homegeneity in the fuel prices.

Alternative Parameter Estimates

The parameters in REM, as in any model, are subject to uncertainty and are likely to change over time. To test the robustness of the model, it would be desirable to reestimate some of the key parameters, perhaps using different estimation techniques or different data sets, and then to carry out simulations using the new parameters. This was not possible within the scope of the assessment project. However, it was feasible to take industrial demand parameter estimates from some earlier materials dealing with REM and use these as alternative parameters in some simulation experiments.

The parameters from the current REM industrial demand model and the two alternative parameter sets are shown in Table 3.10. The Case 1 parameters are estimated for data for 1968-72, as were the original parameters, and are similar to the original parameters. The Case 2 parameters were estimated with 1962-67 data and are drastically

Table 3.10

Alternative Parameters for Industrial Demand Relationships

Industrial State Allocation

$$\text{LOG}\left(\frac{\text{ENERGY IN STATE i}}{\text{ENERGY IN CALIF.}}\right) = A\cdot \ \text{LOG}\left(\frac{\text{AVERAGE PRICE IN i}}{\text{AVERAGE PRICE IN CALIF}}\right)$$

$$B\cdot \ \text{LOG}\left(\frac{\text{POPULATION IN i}}{\text{POPULATION IN CALIF}}\right)$$

$$C\cdot \ \text{LOG}\left(\frac{\text{ENERGY (-1) in i}}{\text{ENERGY (-1) IN CALIF}}\right)$$

	Original[1]	Case 1[2]	Case 2[3]
A	-0.156	-0.170	-0.034
B	0.047	0.054	0.013
C	0.927	0.916	0.976

Industrial Fuel Split

$$\text{LOG}\left(\frac{\text{GAS}}{\text{ELECTRICITY}}\right) = A \cdot D\cdot \ \text{LOG}\left(\frac{\text{GAS PRICE}}{\text{ELECTRICITY PRICE}}\right) \cdot E\cdot \ \text{LOG}\left(\frac{\text{GAS (-1)}}{\text{ELECTRICITY (-1)}}\right)$$

$$\text{LOG}\left(\frac{\text{GAS}}{\text{ELECTRICITY}}\right) = B \cdot D\cdot \ \text{LOG}\left(\frac{\text{OIL PRICE}}{\text{ELECTRICITY PRICE}}\right) \cdot E\cdot \ \text{LOG}\left(\frac{\text{OIL (-1)}}{\text{ELECTRICITY (-1)}}\right)$$

$$\text{LOG}\left(\frac{\text{COAL}}{\text{ELECTRICITY}}\right) = C \cdot D\cdot \ \text{LOG}\left(\frac{\text{COAL PRICE}}{\text{ELECTRICITY PRICE}}\right) \cdot E\cdot \ \text{LOG}\left(\frac{\text{COAL (-1)}}{\text{ELECTRICITY (-1)}}\right)$$

	Original[1]	Case 1[2]	Case 2[3]
A	-0.231	-0.357	-0.043
B	-0.354	-0.489	-0.160
C	-0.540	-0.650	-0.143
D	-0.301	-0.323	-0.083
E	0.856	0.844	0.940

[1] From [7], estimated for 1968-1972.

[2] From [4], estimated for 1968-1972.

[3] From [4], estimated for 1962-1967.

different. There is no reason to think that the parameters in either of these cases are more accurate or superior to the original parameters. The purpose of the experiments is not to come up with better parameters but to test the REM response to "reasonable" changes in the parameters of the industrial demand model.

The results of introducing the two alternative sets of industrial demand parameters (Case 1 and Case 2) are shown in Table 3.11. Even though the Case 1 parameter estimates are quite similar to the original estimates, by 1995 industrial energy demands differ appreciably from the base case results. The projected gas and oil demands are well below baseline while electricity demand is well above baseline. Gas, oil, and electricity demands in 1995 under the base case are 7.3 quads (37 percent), 1.5 quads (8 percent) and 8.2 quads (41 percent), respectively, while the Case 1 parameters generate gas, oil, and electricity demands of 4.6 quads (26 percent), 1.0 quads (5 percent), and 9.9 quads (55 percent), respectively. The compositional effects on electricity supply are essentially zero. The effects of Case 2 parameter estimates are quite different. Industrial gas demand rises considerably above the base case while electricity demand drops. Furthermore, the total industrial demand for energy increases in Case 2 relative to the base case, while in Case 1 it decreases.

The results of these experiments show that the REM projections are quite sensitive to changes in the demand parameters. The acquisition of new data, the use of different sample periods, or the application of different estimation techniques can produce parameter estimates that will

Table 3.11

U.S. Energy Demands and Electricity Supply for Alternative Estimates of Industrial Demand Parameters

	Case 1		Case 2	
	1975	1995	1975	1995
U. S. ENERGY DEMANDS* (Quadrillion BTU's)				
Residential/Commercial				
Total	14.0	15.9	14.0	16.0
Gas	6.7 (48)	6.3 (39)	6.7 (48)	6.2 (39)
Oil	4.0 (28)	3.5 (22)	4.0 (28)	3.4 (22)
Electricity	3.3 (24)	6.2 (39)	3.4 (24)	6.3 (40)
Industrial				
Total	15.4	18.0	16.7	23.2
Gas	8.5 (55)	4.6 (26)	10.2 (61)	12.6 (54)
Oil	1.8 (12)	1.0 (5)	1.7 (10)	1.3 (6)
Electricity	2.9 (19)	9.9 (55)	2.1 (12)	5.4 (23)
Coal	2.2 (15)	2.5 (14)	2.8 (17)	4.0 (17)
Total				
Total	29.5	33.9	30.7	39.2
Gas	15.2 (51)	10.9 (32)	16.9 (55)	18.8 (48)
Oil	5.8 (20)	4.4 (13)	5.6 (18)	4.7 (12)
Electricity	6.3 (21)	16.2 (48)	5.4 (18)	11.7 (30)
Coal	2.2 (8)	2.5 (7)	2.8 (9)	4.0 (10)
U. S. ELECTRICITY SUPPLY*				
Installed Generation Capacity (GW)				
Total	466.5	1104.2	441.3	745.7
Nuclear	43.1 (0)	394.7 (36)	43.1 (10)	277.8 (37)
Coal	200.7 (43)	531.4 (48)	195.0 (44)	413.4 (42)
Oil and gas	175.7 (38)	111.5 (10)	159.0 (36)	99.0 (13)
Internal Combustion	47.0 (10)	66.6 (6)	44.2 (10)	54.5 (7)
Electricity Generation (MMWH)				
Total	1706.4	4713.1	1432.3	
Nuclear	276.2 (16)	2670.9 (57)	276.2 (19)	1854.6 (57)
Coal	937.6 (55)	1989.4 (42)	877.8 (61)	1271.3 (39)
Oil and gas	486.5 (29)	37.5 (1)	273.1 (19)	135.2 (4)
Internal Combustion	6.1 (0)	15.7 (0)	5.2 (.3)	17.5 (.1)
Price of Electricity (mills/Kwh)	26.7	78.8	27.0	81.5
Total Utility Assets ($ billions)	178.6	1534.1	164.5	1137.9

* Shares of totals shown (in percent) in parentheses

substantially alter the REM outputs. This finding is hardly surprising, but it stresses the need for careful sensitivity analysis as part of any policy application employing REM.

3.4 Supply Submodel

3.4.1 Outline of the supply submodel

The supply submodel simulates the two most critical decision processes involved in the operation of the electric utility system. First, during each time period, electric utilities have to determine which generating plants should be utilized in order to meet current demands for electricity. The second decision concerns the investments in new plant and equipment that now have to be made in order to meet future demands for electricity. As discussed in Chapter 2, the decision processes in the supply submodel require as inputs from the other REM submodels estimates of demands for electricity and the capital charge rate (see Figure 2.1). In addition, the supply submodel requires current and projected values for a number of exogenous factors, including fuel prices, shape of the load duration curve, and technical characteristics of the different types of generating plants. The outputs from the supply submodel provide the other REM submodels with estimates of production costs and capital expenditures.

The major behavioral processes in the supply submodel are simulated in the three components: electricity generation, generation expansion, and transmission and distribution. In addition, the supply submodel contains three modules that process the input data required by the generation expansion model. These modules deal with load prediction, exogenous factor forecasts, and the nuclear fuel cycle. A schematic outline of the relationships among these components is given in Figure 3.2.

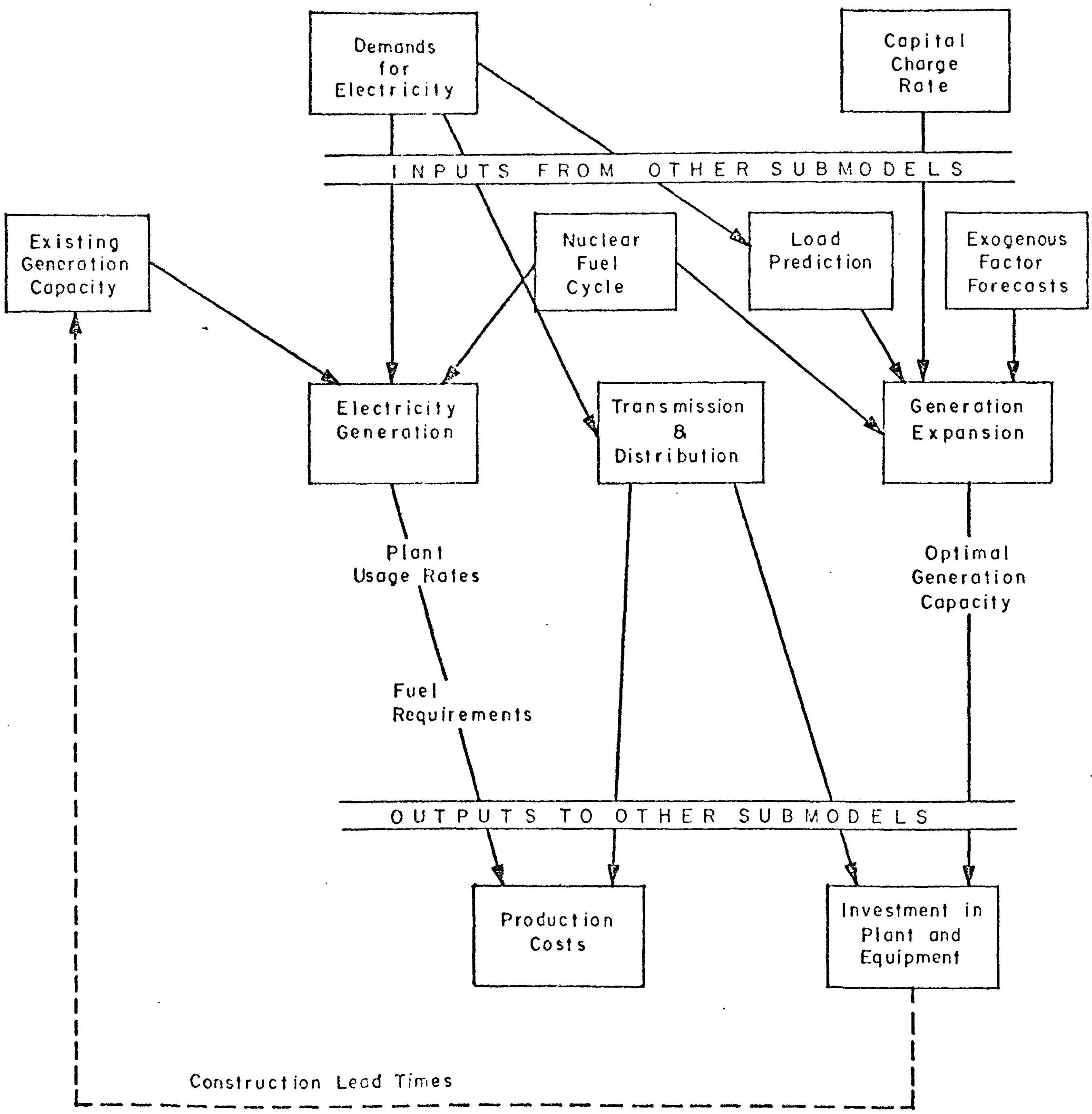


FIGURE 3.2 SCHEMATIC OUTLINE OF THE COMPONENTS OF THE REM SUPPLY SUBMODEL

Given the current demands for electricity and the composition of the existing generation capacity, the electricity generation component assumes that utilities use cost-minimization rules to determine which plants will be utilized to meet those demands. The resulting estimates of the usage rates for each type of plant are, in turn, used to determine the fuel requirements and total production costs incurred in electricity generation.

Total production costs incurred by the electric utility industry include, in addition to generation costs, the cost of operating and maintaining the transmission and distribution (T&D) system. These are estimated in the T&D component on the basis of the estimated demands for electricity and exogenous factors such as the geographical characteristics of the service areas. The T&D component also estimates the amount of capital investments that have to be made to provide the equipment needed to supply electricity to the users.

The function of the generation expansion component is to determine the capital investments necessary to bring the appropriate amount and mix of new generating capacity on-line in time to meet future electricity demands. This planning process requires input information concerning the expected future values for the relevant variables. The load prediction module simulates the process by which utilities forecast load levels by applying trend extrapolation procedures to the demand levels observed up to the current time period. Another forecasting module produces projected values for the exogenous factors required by the generation expansion model, assuming that utilities make forecasts by applying trend extrapolation to past values for the exogenous factors.

The module dealing with the nuclear fuel cycle is quite detailed, but its basic function is to provide the generation expansion component with estimates of the supply curves for the various types of nuclear fuels. This, together with the mass balance accounting also carried out in this module, provides the information needed to estimate the current and expected costs of operating the various types of nuclear reactors.

The final key piece of information required by the generation expansion component is the estimate of the capital charge rate. This is supplied by the REM financial/regulatory submodel. The generation expansion component assumes that utilities use optimization rules based on cost minimization to find the optimal configuration of future generating capacity. It is further assumed in selecting this optimal mix that the utilities act as if the optimal system were being built from scratch; that is, the existing capacity is ignored in determining the optimum. A reconciliation between the optimum and existing is then made to determine the desired additions.

Current period capital commitments are determined by the difference between the desired capacity mix and the capacity mix that would exist if no investments were made. As is shown by the dashed line in Figure 3.2, the investments made in this period will determine the generation capacity that will be available in future time periods. The lead times involved depend on the type of plant being constructed. The lead times used in REM are two and one-half years for peaking plants, five years for conventional steam plants, and ten years for nuclear plants.

3.4.2 Overview evaluation

The supply submodel is so large and performs so many different functions that the overview evaluation will be presented in five parts: (1) electricity generation; (2) generation expansion; (3) transmission and distribution; (4) nuclear fuel cycle; and (5) load prediction and exogenous factor forecasts. In the case of electricity generation and capacity expansion, the model needs to be outlined in considerable detail in order to lay the necessary groundwork for the subsequent in-depth analysis. Therefore, the discussion of these two components is further broken down into: (a) a detailed summary of model logic, and (b) a presentation of the overview assessment.

Electricity Generation: Model Logic

The electricity generation component determines the plant utilization rates and production costs incurred in meeting current demands for electricity. The procedures used to simulate the decision processes involved are described by the authors as follows:

> At the time production decisions are made all installation (initial investment) costs are sunk costs and only operating costs (fuel plus variable operation and maintenance costs) are used for determining the generating profile. The guiding principle is to use the least operating cost plant as much as possible and, conversely, the highest operating cost as little as possible. In the model each of the nine plant alternatives is ranked according to its merit of operation corresponding to the level of fuel and operating costs. The total kilowatt hour demand is then generated by consecutively adding the available energy output from each plant type according to its rank in the merit order until the total demand is generated [33].

The production cost minimization procedures described in this quotation are implemented in REM using the following sets of relationships. First, the maximum available electricity generation for plant type j in region i, AVAGEN(i), is given by:

EFFCAP (i,j) = EXSCAP (i, j) * AVAFAC (j)

AVAGEN (i,j) = EFFCAP (i, j) * 8.76 * RDUTYC(j)

where:

EFFCAP (i, j) = effective capacity of plant type j in region i,

EXSCAP (i, j) = existing capacity of plant type j in region i,

AVAFAC (j) = availability factor of plant type j,

RDUTYC (j) = maximum possible duty cycle of plant type j.

It should be noted that definitions of "availability factor" and "maximum duty cycle" are somewhat different from the conventional meanings of these terms. Duty cycle in REM is defined as the proportion of the total hours in a year that a plant is available for use. The term usually used to describe this proportion is "availability factor." This proportion takes into account the amount of time that the plant is scheduled to be shut down for planned maintenance. The "availability factor" in REM is the reduction in effective plant capacity due to forced outages. Since these outages are random, the effect is averaged throughout the year and results in a derating of the plant's capacity. Finally, the available documentation defines the term "usage factor" as [34]:

$$\frac{\text{actual electrical generation}}{\text{installed capacity * 8760 hours}}$$

The more conventional term used to describe this ratio is "capacity factor" or "plant factor".

Production costs are calculated in the electricity generation model using an heuristic algorithm that ranks plants on the basis of average operating costs, that is, fuel plus operation and maintenance costs. Capital costs do not enter into these calculations since they are treated as sunk costs. The application of this algorithm is illustrated in Figure 3.3. The variable DIFGEN (j) represents the shortfall or surplus of generating capacity that results when a plant type j is ranked under the load duration curve:

DIFGEN (j) = AVAGEN (j) - DEMGEN (j)

where:

DEMGEN (j) = the amount of electricity generated by plant type j if there were no duty cycle constraints, i.e., if plants were capable of operating through the entire year if desired.

Positive amounts of DIFGEN, starting with the lowest cost plants, are used to fill the negative amounts until the deficit is completely filled. The total cost of production is then calculated by summing energy costs of all of the plant types being used. Finally, the "usage factor" is calculated from the ratio:

$$\text{USAGE} = \frac{\text{Electricity generated from plant type j after the generation mix is finalized}}{\text{Existing capacity of plant type j} * 8.76}$$

Electricity Generation: Overview Assessment

In order to clarify the interpretation of the REM methodology, a simplified annual load curve is shown in Figure 3.4. This represents a case where there is a single peak in electricity demand during the course

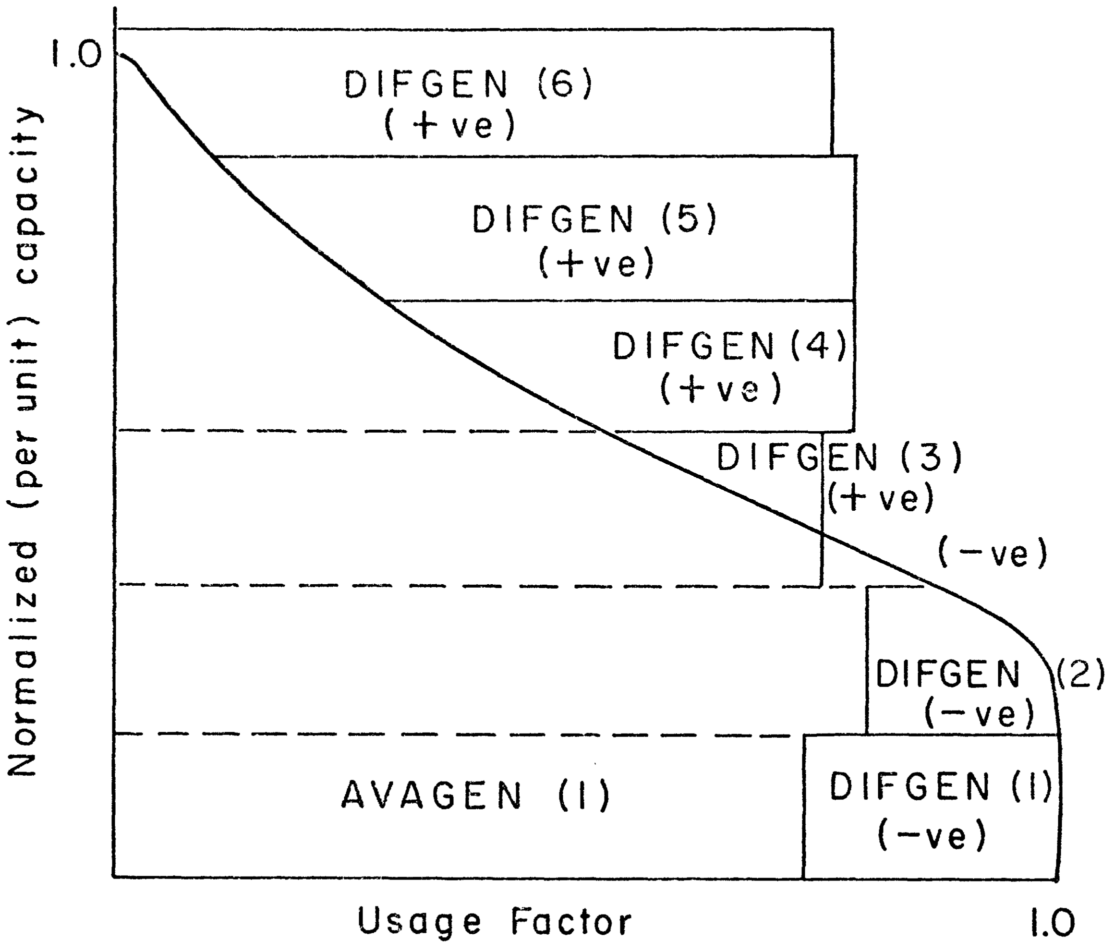


FIGURE 3.3 SHORTFALLS AND SURPLUSES OF ELECTRICITY GENERATION FOR THE HYPOTHETICAL CASE

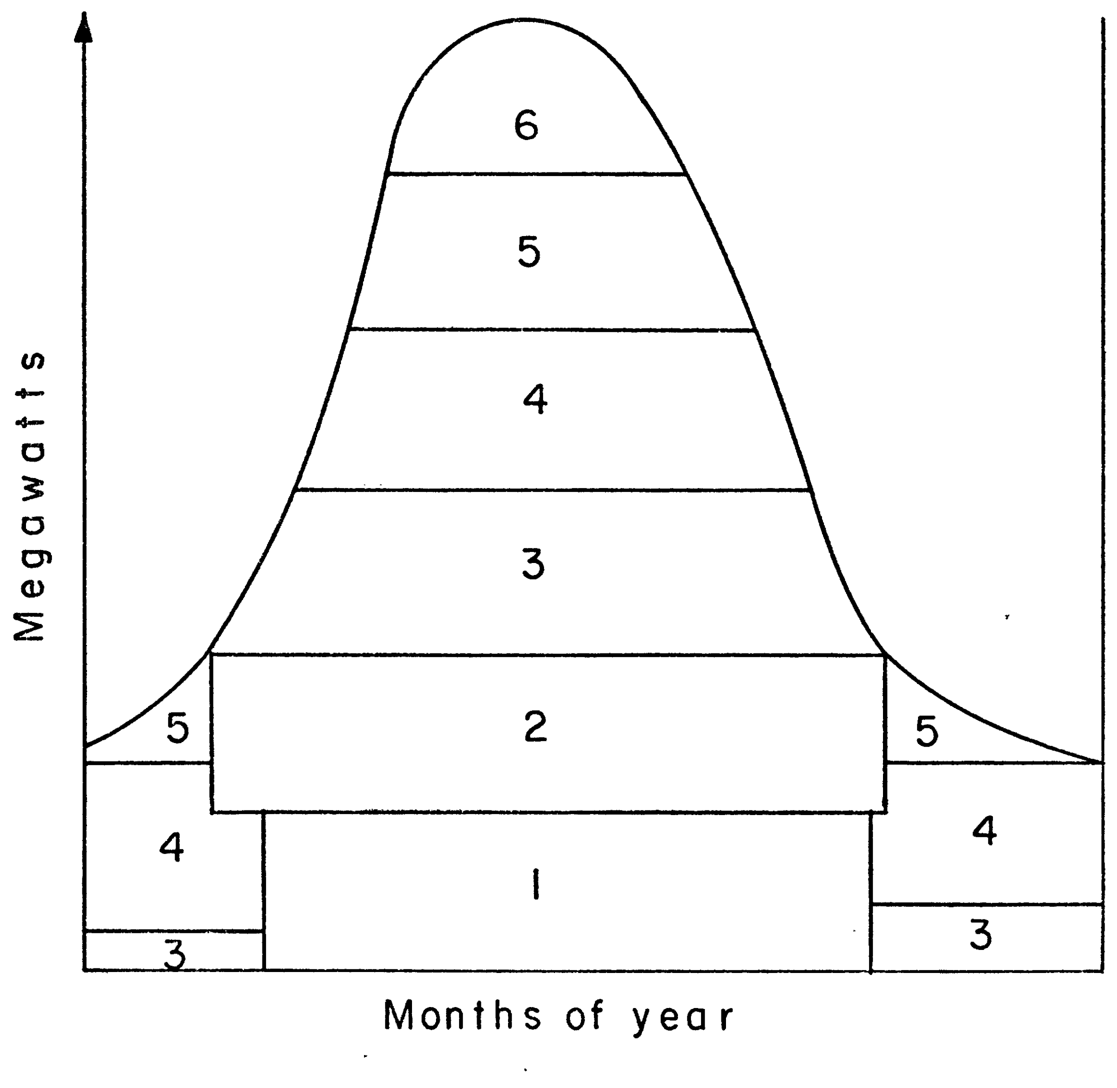


FIGURE 3.4 ANNUAL LOAD CURVE, BASELOAD MAINTENANCE SCHEDULED DURING OFF-PEAK*

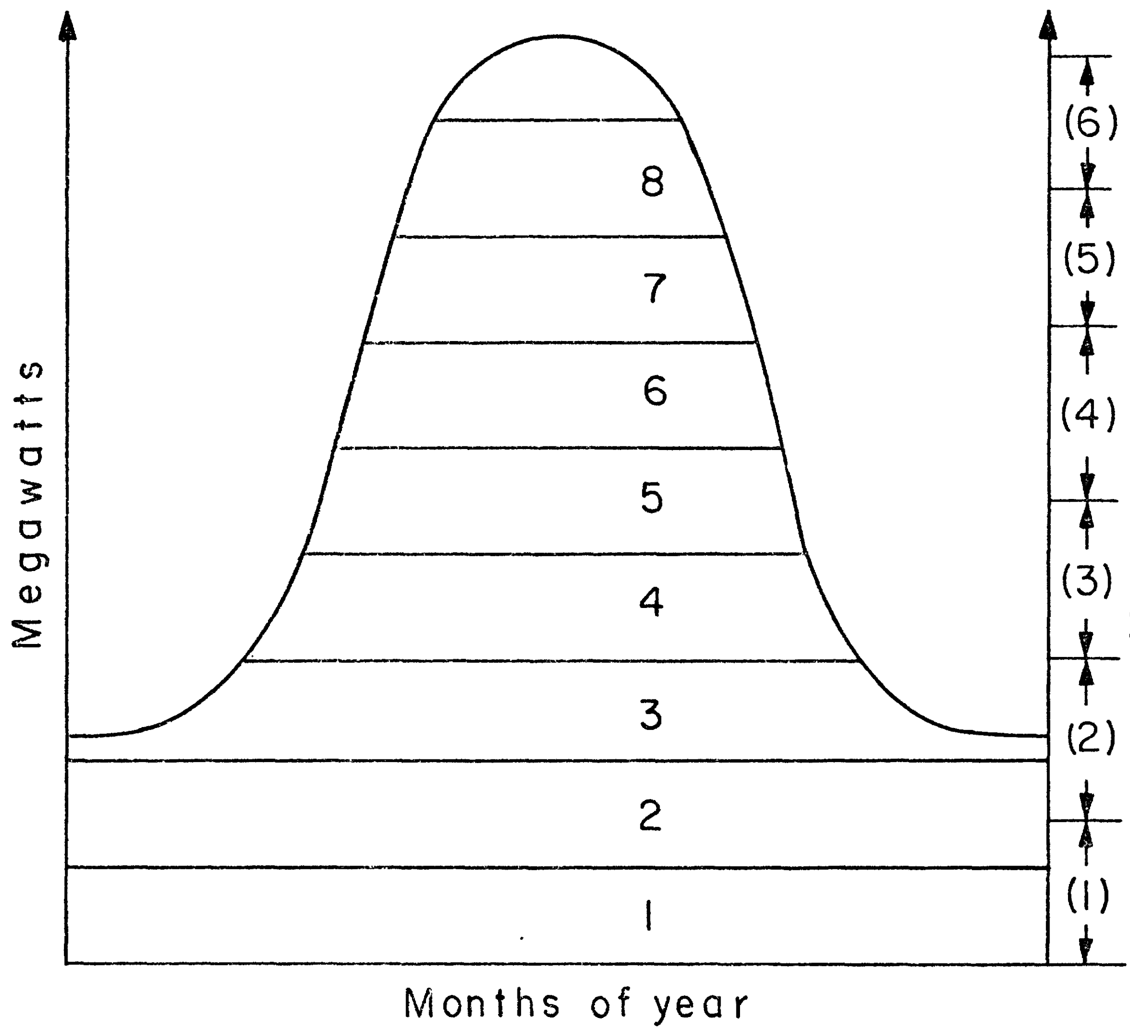
of the year. Thus, it is not realistic for the U.S., although the assumed seasonal pattern is comparable to that underlying Figure 3.3. Plant types 1 and 2 are baseload plants that are utilized to their maximum availability. Plant types 3, 4, and 5 are cycling plants which, in addition to being used to meet part of the peak period demands, are used as needed during the off-peak period. Plant type 6 is utilized only during the peak demand period.

An implicit assumption underlying this methodology is that all plants of types 1 and 2 can be scheduled for maintenance during the off-peak period. Suppose, for example, that plant type 1 is a nuclear light water reactor (LWR). In this case, the assumption is that maintenance on all the LWR's in a given region can be successfully completed during the off-peak period. If the region has only a small number of reactors, then the assumption may be plausible, but if by 1990 the region has nuclear as a significant part of its capacity, then it is quite unlikely that there would be adequate maintenance facilities to service all of these reactors in the off-peak period.

By assuming that all of the low-cost baseload plants are always available (after allowing for forced outages) during the peak-load periods, the algorithm in REM represents the most optimistic way of operating the power system. It produces a lower bound estimate of production costs. To the extent that this assumption is not valid, REM will tend to underestimate the usage rate on the oil and coal cycling plants. Internal combustion peaking units, such as gas turbines, may not be operated at all. This last deficiency in the basic production scheduling algorithm is dealt with in REM by imposing an arbitrary constraint on the system. "Since it is possible to get no generation from internal combustion units with this scheme, the generation from the latter is assumed to meet at least 0.3% of the total generation requirements" ([5]). Examination of the published results produced by REM shows that this constraint is always effective; that is, the REM simulations always show exactly 0.3 percent of total generation being met by internal combustion units. Thus, the amount of electricity produced by peaking units is not something that comes out of the analysis in REM but is, in effect, an exogenous input.

An alternative methodology that REM could have used would have been to assume that plant outage occurs evenly throughout the year, resulting in a reduced but continuously available effective capacity. This situation is illustrated in Figure 3.5. Relative to the approach used in REM, the constant maintenance schedule assumed in Figure 3.5 will result in higher production costs and will require greater use of internal combustion units during the peak period.

Further insight into the adequacy of the REM scheduling logic is obtained by comparing the deterministic approach in REM with a probabilistic model capable of more accurately simulating the utilization of peaking units. Figure 3.6 illustrates the hourly and weekly loading ranges of a hypothetiical utility throughout the year. Within these ranges there is a wave pattern. This upper bound of the range represents the peak for that week, and the lower bound represents the lowest point, generally in the early hours of Sunday morning. Often the latter is only half of the peak for the week.



* Numbers in parentheses refer to the plant types used in the previous scheme, Figure 3.4; other numbers refer to plant types

FIGURE 3.5 ANNUAL LOAD CURVE BASELOAD MAINTENANCE SCHEDULED EVENLY THROUGHOUT YEAR*

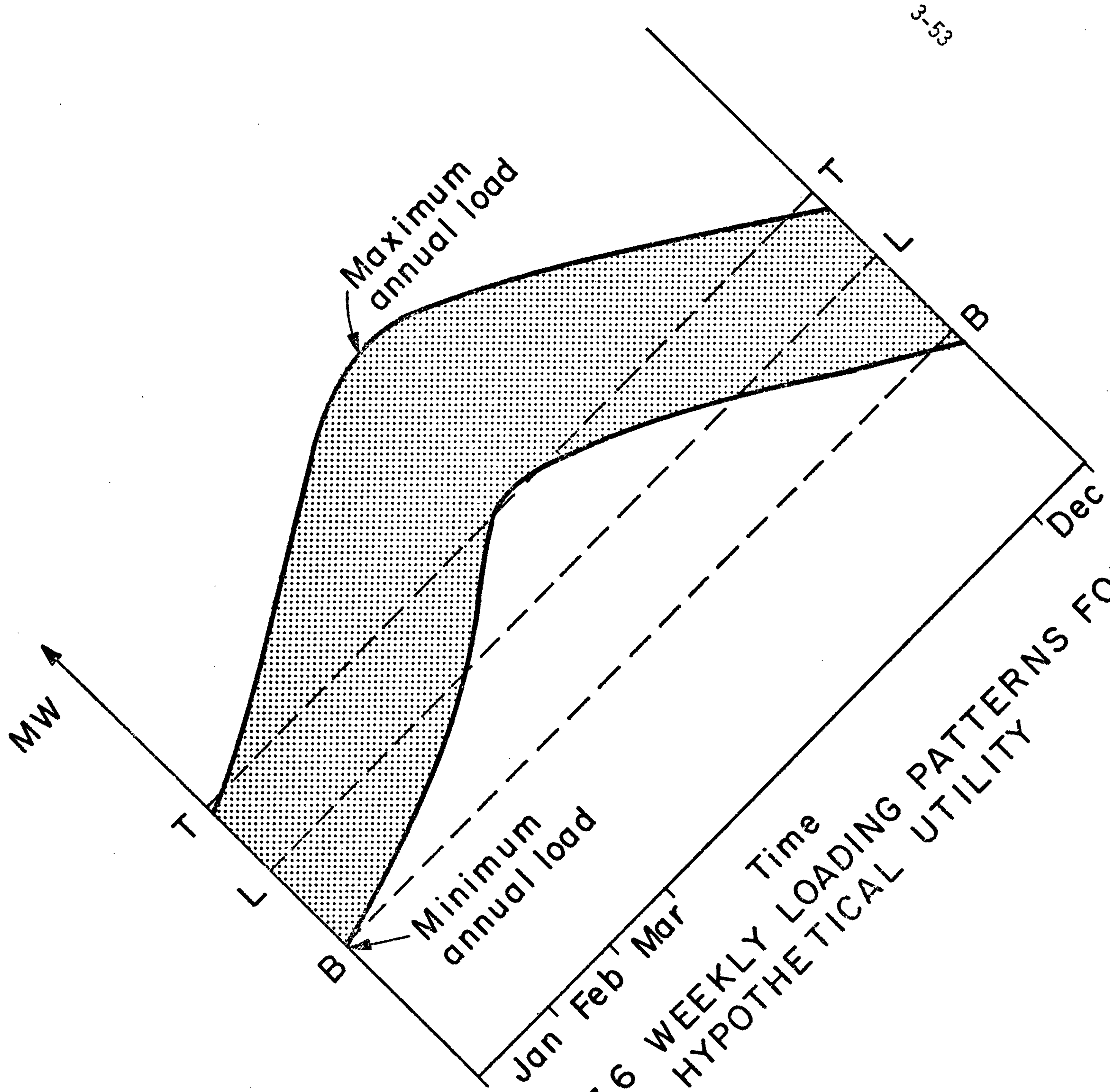


FIGURE 3.6 WEEKLY LOADING PATTERNS FOR A HYPOTHETICAL UTILITY

The annual load duration curve used in REM is an ordering of the hour-by-hour loadings of the power system, so they fall left to right on the diagram. With this procedure, all time relevance of the loading patterns is lost. Baseload plants will supply an unrealistically high proportion of total demand while peaking units will be underutilized or not used at all.

Baseloaded generation is defined as that which can be permanently left on load through the week. The total area between the lower bound and the time axis is therefore the maximum amount of baseloaded plant that can be used. It is important to realize that electricity above the loading line given by BB is supplied intermittently whenever the time of the year is such that the daily load is cycling through the load in question. For example, consider load LL. At the center of the curve (say, during the summer), LL is obviously a baseload, but at the edges of the loading graph, LL must be supplied by a cycling plant. This fact is glossed over in an annual load duration curve representation, which would imply that everything below LL can be continuously supplied (i.e., supplied at baseload). Because some baseloaded plants cannot be used from level TT downwards, they will be taken out for maintenance. This process will continue as the load comes away from the seasonal peak. The probabilistic nature of the loading pattern may be more adequately represented in a deterministic model such as REM by assuming that maintenance is scheduled evenly throughout the year.

It is worth noting that the generation simulators used by electric utilities are considerably more sophisticated than the electricity generation model in REM. The utility models commonly employ probabilistic simulation, incorporate many more types of generating plants, and take into account seasonal factors. The use of an annual load duration curve in REM, although a reasonable simplifying assumption for some purposes, restricts the applicability of the REM results. The utilization of peaking and cycling plants follows different patterns at different times of the year. Under some circumstances, this could significantly affect production costs. While the use of seasonal load duration curves would certainly provide a better representation of the real situation, it is not clear whether this factor is crucial to the types of issues being addressed by REM.

The assumptions underlying Figures 3.4 and 3.5 represent the two opposite extremes with regard to maintenance scheduling. Figure 3.4 may be excessively optimistic in assuming that all maintenance can be scheduled during the off-peak periods, while Figure 3.5 may be unduly pessimistic in assuming that utilities are not at all successful in adapting their maintenance schedule so more plants are available during periods of peak demands. Perhaps a more realistic and flexible way of dealing with this issue would be to take an intermediate position by assuming that utilities are able to schedule a disproportionate share, but not all, of the required maintenance during the off-peak periods. This situation is depicted in Figure 3.7 (which can be compared with Figure 3.3), where most but not all of the baseload units are available during the peak demand period, and most but not all of the maintenance is scheduled during the off-peak periods. This would seem to be a better

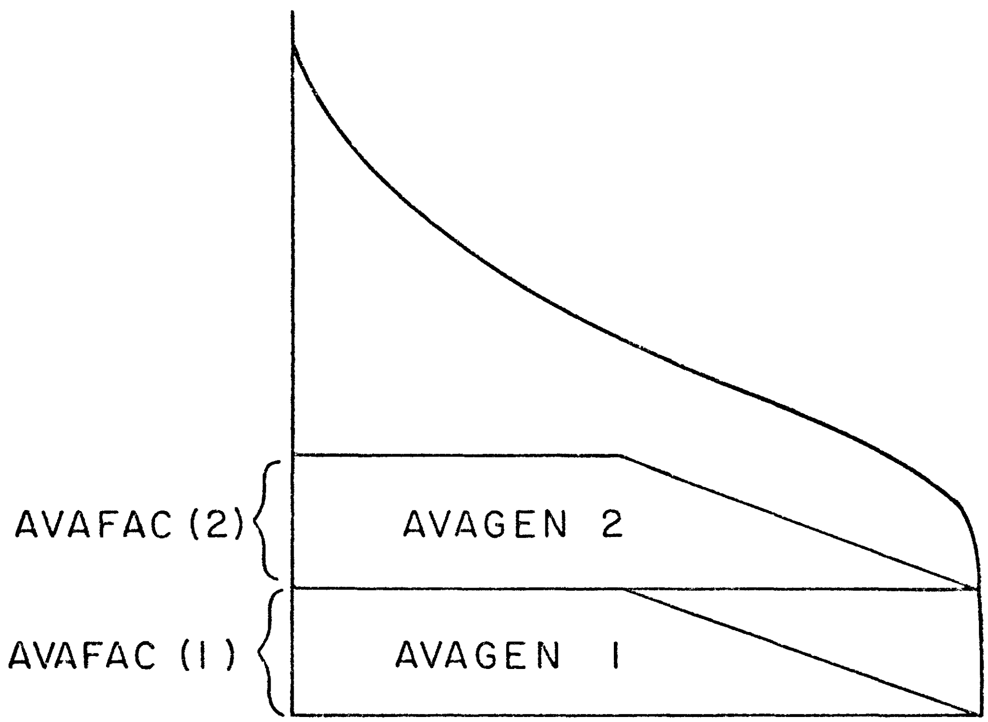


FIGURE 3.7 LOAD DURATION CURVE

representation of actual utility practice, particularly in regions where there are significant numbers of plants for each plant type. Except for the difference in the timing of plant availability, this approach could use the same algorithms as the current electricity generation model. Therefore, it would not require major restructuring of REM to incorporate this feature.

A factor that seems to have important implicatons for the REM applications is the exogenously imposed limit by nuclear LWR utilization rates prior to 1974. This limit, which is called a "clipped duty cycle," is introduced in order to force the model to track the historical record. In the absence of this constraint, REM significantly overestimates the amount of electricity being generated in nuclear plants during the historical period. The problem is that this constraint is removed after 1974. This has the effect of producing a substantial increase in the amount of nuclear energy that is available to the electric utility system. It is true that nuclear plants usually have decreased availability in the first few years. Then, as the plants mature, their reliability and availability increase. However, that is not the process being modeled in REM, since the clipped duty cycle applies to the system as a whole and not to individual plants. There is no indication of what factors led to the clipped duty cycle during the historical period, and more importantly, there is no indication of why those factors should cease to be relevant during the projection period. By dropping this constraint during the projection period, it is implied that in the future it will be possible to use nuclear plants for a much greater proportion of the year than has proven feasible up to now.

The exogenously specified availability factors and duty cycles (or forced outage and planned outage rates, respectively) are important parameters in REM for all types of generating plants, not simply for nuclear plants. The values assigned to these parameters in the REM base case are shown in Table 3.12. Comparable parameters are also shown for a large utility, Commonwealth Edison, derived from data reported for March 1977. Although any implications drawn from these comparisons should be regarded as impressionistic only, it appears that the REM parameters are quite optimistic relative to observed practice. This is particularly significant with regard to nuclear plants, since they are the primary baseload plants in REM and therefore tend to be used to the full extent they are available. If the parameters for availability factors and duty cycles are set too high in REM, then nuclear producton costs would be underestimated in the REM projections. Over time, this would also tend to lead to excessive amounts of investment in nuclear capacity. Clearly, this issue is vital to many of the REM applications.

Generation Expansion: Model Logic

The task of expanding the generation capacity in each of the nine regions in REM is accomplished in two portions of the computer program. The first portion (subroutine OPPLAN) computes the ideal, start-from-scratch mix of generation for each region for each half-year to the end of the planning horizon. The second portion (contained in the MAIN or supervisor subroutine) determines how the system will move toward the optimum mix given the existing and committed generation, minus the capacity due for retirement.

Table 3.12

Availability Factor and Duty Cycle Parameters

	Commonwealth Edison for 1977			Regional Electricity Model Region 4 for 1980		
	Availability Factor Hrs/8760	1-Forced Outage Rate	Capacity Factor	Duty Cycle	"Availability Factor"	Projected Capacity Factor
Nuclear	0.72	0.88	0.57	0.86	0.85	0.73
Coal	0.67	N.A.	0.46	0.96	0.95	0.63
Oil	0.85	N.A.	0.39	0.96	0.95	Nil

The optimum plant capacity configuration (OPPLAN) is computed for three intervals corresponding to the three construction lead times for the different types of facilities. At each point in time, the commitment of all nuclear plant types is decided to the point in the future that represents the nuclear lead time requirement (10 years). The fossil plant commitments are also decided to the point in the future that represents the fossil plant lead time (5 years). Internal combustion gas turbines require the least lead time (2.5 years) and thus involve no use of OPPLAN, as they just take up the remaining slack in the system.

Figure 3.8 outlines the sequence of steps in OPPLAN. The most important OPPLAN equations and the computer code are summarized in Table 3.13. The first step in OPPLAN uses the projected values for fuel costs and plant investment costs to estimate the generation costs (per Btu) as a function of usage.* The resulting cost curves, which are held within OPPLAN in functional form on the basis of two parameter descriptions, are illustrated by the curves shown in the top half of Figure 3.9.

The second step involves the determination of all possible intersection points of the cost curves. This is easiest to perform for the complete set of intersection points. Thus, the third step is the sorting out of the intersection points, even those that are not on the

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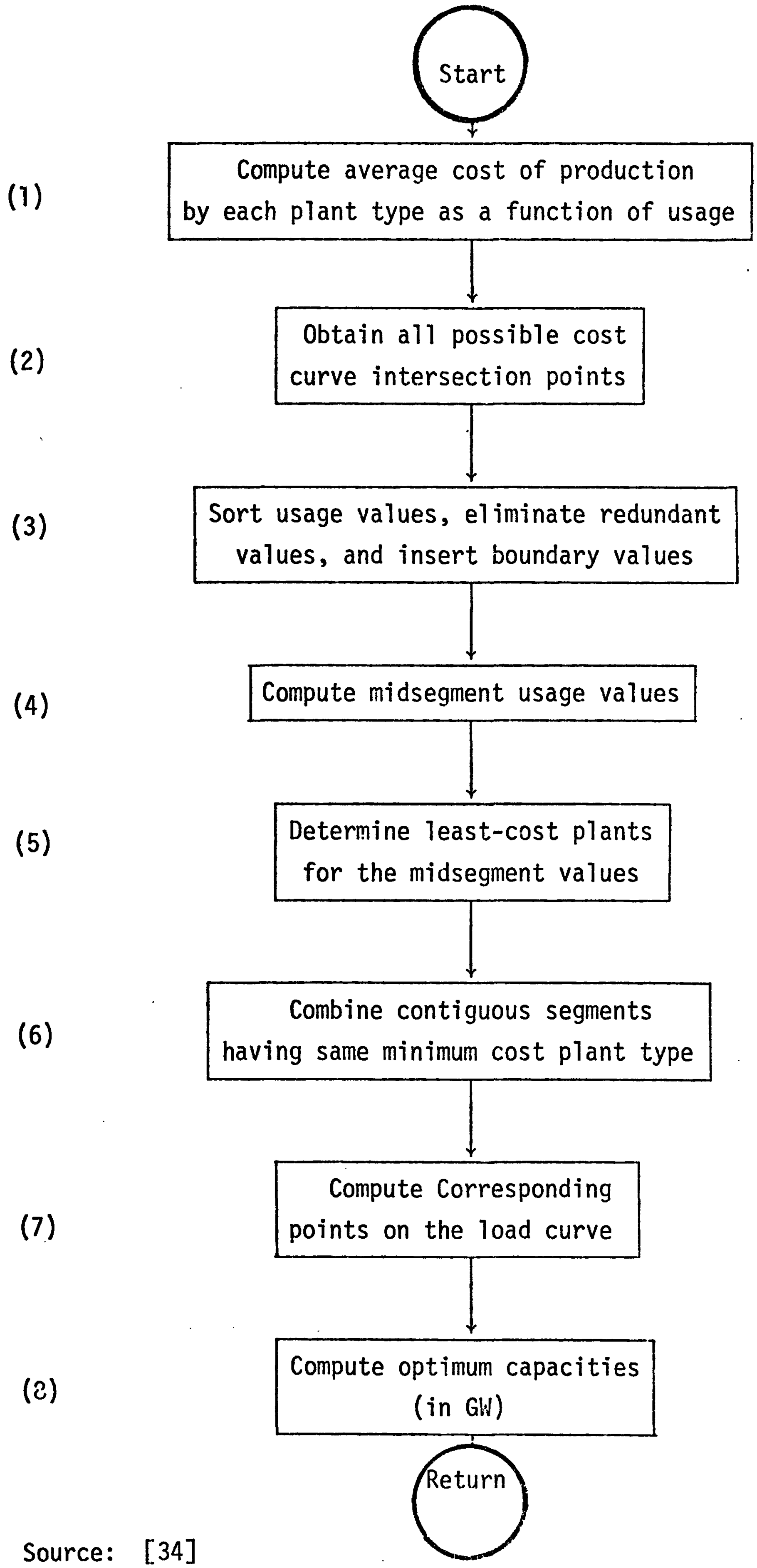
*The equation for the first component of production costs, PA(j), contains an error that has been pointed out to us by the authors of REM. The AVAFAC and DUTMAX terms in the denominator should be deleted. This error has been corrected in the most recent version of REM but was still present in the version of the model supplied to us and used in our experiments.

Figure 3.8

Broad Flow Diagram of Subroutine Applan
(Capacity Expansion Planning)



Source: [34]

Table 3.13

KEY EQUATIONS DETERMINING OPTIMUM PLANT CAPACITY CONFIGURATION*

Step 1: Cost Curve Computations

1. Usage Dependent Per Unit Energy Cost

$$PA(j) = \frac{CHRATE\ (i) * (PCAPIT(j, k) + CFULK2(j))}{8.76 * AVAFAC\ (j) * DUTMAX\ (j)}$$

where: PA(j) = usage dependent component of production cost

CHRATE(i) = capital charge rate in region i

PCAPIT(j,k) = predicted capital cost of plant type j for horizon year k

CFULK2(j) = cost of nuclear fuel loading for plant type j

AVAFAC(j) = availability factor for plant type j

DUTMAX(j) = maximum allowable duty cycle for plant type j

2. Usage Independent Per Unit Energy Cost

PB(j) = CFULM2(j,k) + POAMCO (j,k)

where: PB(j) = usage independent component of production cost

CFULM2(j,k) = predicted fossil fuel cost for plant type j for horizon year k

POAMCO(j,k) = predicted O & M cost for plant type j for horizon year k

Step 2: Determine Intersection Points

$$USEVAL(n) = \frac{PA(j) - PA(k)}{PB(k) - PB(j)}$$

where: USEVAL(n) = the n usage values at the cost curve intersection points.

Step 3: through 6: Determine Optimum Plants and Their Usage Values

These are sort and check equations resulting in a new set of

USEVAL(m) = the m usage values that define the start and stop of all "optimum" cost curve segments, and

IPLANT(n) = the type of plant that is optimum between usage values USEVAL(n) and USEVAL(n + 1).

Table 3.13 (cont.)

Step 7: Determine Intersection Points on Load Duration Curve

TLOADC(j) = trapezoidal determination of fraction of the peak load duration curve that is equivalent to the usage value j.

Step 8: Determine Optimum Capacity Levels

1. Known Capacity Additions

FRAC = TP/PREPCD(k)

where FRAC = fraction of known hydro or hydro and nuclear capacity compared to predicted total peak capacity for horizon year k.

TP = known hydro or hydro and nuclear capacity at horizon year.

PREPCD(k) = total peak capacity predicted for year k

2. Optimum Capacity Levels

CAPOP(j)= PREPCD(k) * (TLOAD(j) - TLOAD(j + 1) * (1 - FRAC)

where CAPOP(j) = optimum capacity level for plant type j at the horizon year

3. Reflecting Need for Reserve

OPTCAP(i,j)= CAPOP(j) * OVECAP

where OPTCAP (i,j)= reserve adjusted optimum capacity for plant type j in region i

OVECAP = overcapacity factor.

* Steps 1-8 correspond to the steps in Figure 3.8

Source: [34]

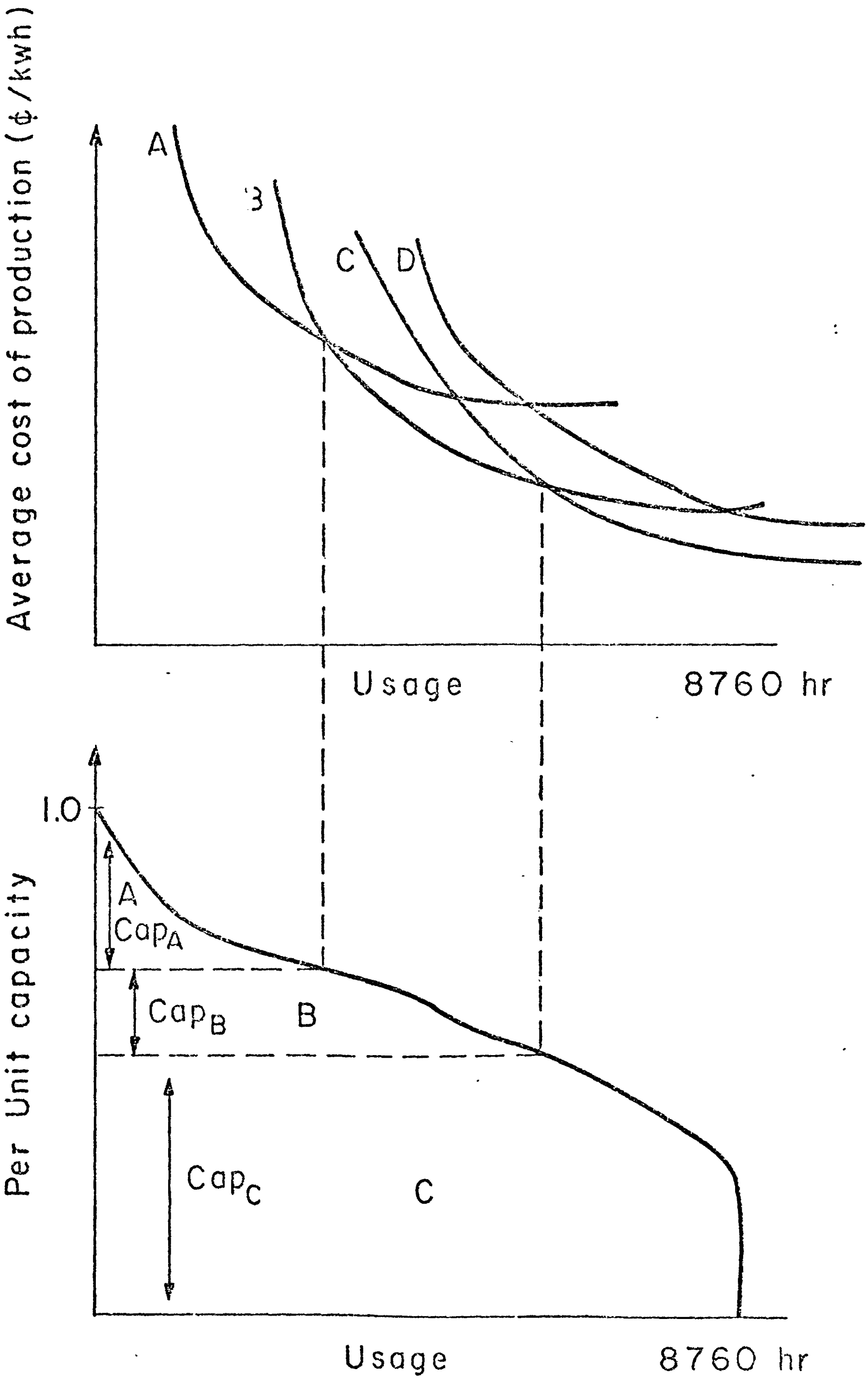


FIGURE 3.9 GEOMETRICAL REPRESENTATION OF THE CALCULATION OF OPTIMUM CAPACITIES FOR SUBROUTINE OPPLAN

Source: [34]

envelope of the "optimum" curve, and the identification of special cases involving one or no intersections. Next, the optimum segments of the curve are identified by computing midpoints between all intersection points (step 4), iteratively checking all curves at these midpoints (step 5), and then storing the optimum plant type choices together with the range of usage over which they are the optimum choice (step 6). If OPPLAN is being used for the shorter time horizon, where nuclear plant types are of known capacity, then the coal plant curve is used to cover all usage values on the baseloaded portion of the cost curve.

The next portion of OPPLAN (step 7) projects the optimum usage intersection points onto the load duration curve, as shown in the bottom half of Figure 3.9. Using an 18-point trapezoidal approximation to the load duration curve, the various "optimum" plant types are assigned the appropriate fraction of peak-load requirements.

The final step involves subtracting the hydro, and nuclear capacity on the shorter planning horizon, from the forecasted peak load, assigning gigawatt capacity levels, and multiplying these levels by the reserve margin factor. Only nuclear plants are multiplied by this factor in the longer horizon planning sessions and only fossil plants in the middle planning sessions. This procedure, though appropriate, is not explained in the documentation.

Having determined the optimal capacity for each plant type, this information is next used to simulate the process by which utilities decide what capacity commitments should be made in the current period. The assumed decision rule is that a utility " . . . only constructs increments corresponding to the difference between desired capacity and existing plant after correction for retirements. ([33], p. 11) Unfortunately, the available documentation does not explain how this rule is actually implemented in REM even though it is of vital importance in determining the results of the generation expansion model. The computer code is also quite cryptic in this area. We interpret the REM procedure as follows: Hydro capacity is first subtracted from the peak. When optimum projections for nuclear are developed, they are checked against existing capacities of all types (accounting for those committed and under construction, and those to be retired) to see if the optimum levels of nuclear plant types can be built without exceeding projected capacity. For each nuclear alternative that is below its projected optimum, the amount that is low is recorded, and the amount of nuclear that can be built is allocated in proportion to these amounts. Likewise, with the three fossil plant alternatives, the alternatives that are underbuilt are planned in proportion to the extent they are lower than optimum. When the capacity in a particular type of plant is greater than the optimum, the excess is used to reduce the estimated need for capacity in other types of plants higher in the merit ordering.

Generation Expansion: Overview Assessment

Modeling the process by which utilities plan for the expansion in future generating capacity is a very difficult process. Expansion planning is as much an art as a science, involving both hard and soft information from virtually all aspects of the utilities' operations.

The decisions will ultimately involve making evaluations and trade-offs among a wide variety of factors, such as economic costs, risks, environmental problems, siting difficulties, availability of fuel supplies, and potential regulatory action or inaction. REM has had to make a number of simplifying assumptions to reduce the modeling problem to manageable proportions.

One step that has been taken in REM is to divide the U.S. electric system into nine regional systems, each of which is modeled as if it were a single utility. This gives some regional dimension to the analysis while still limiting the number of decision-making units that have to be considered. However, it also introduces certain problems of its own. A generation expansion model for a broad geographic region must deal with the problem of aggregating the generation expansion processes in the individual utilities within that region. Since there is no assurance of coordination among these separate efforts, the outcome produced by a number of small systems, each reaching for its own optimum, is likely to be quite different from the outcome produced by a single large utility of the same aggregate size. The individual utilities are likely to be much more constrained by factors such as capital availability, cash flow problems, reliability rules, and site and right-of-way availability. Also, by averaging out the uncertainties associated with fluctuations in demand and forced outages, the process of aggregation may reduce the apparent importance of these factors.

The aggregation problems are so severe that the REM results for an individual region should probably be treated as rough approximations at best. The regionalization is likely to improve the quality of the model's national outputs, but the regional results themselves will be less reliable and probably quite volatile. A more detailed model would be required to deal adequately with a regional power system.

Ideally, a generation expansion model should be capable of incorporating the effects of uncertainty and risk aversion in the decision-making process. For example, it would be desirable to have the model deal with loss of load probability in a direct fashion, rather than simply incorporating a prespecified margin of safety. This is particularly important because loss of load probability is frequently incorporated in the planning models used by the electric utility itself. Since electric utilities are likely to be risk-averse, they will usually pursue a diversified investment strategy. They will base their investment decisions on relative costs of the various types of generating plants, but they are unlikely to put all of their funds into the single, lowest cost option. Instead, they will build a more flexible system by incorporating several different types of generating technology. This is especially likely if the cost differences among the various options are not large.

One way of dealing with some of the effects of uncertainty would be to use a generation expansion model that combines an optimizing model with a systems simulator. The optimizing model, since it will invariably make many simplifying assumptions, can provide only a rough guide for first approximation to the appropriate expansion plans. The systems simulator would then be used to see how these plans are likely to work out in practice. The results of the systems simulation could be used to evaluate the assumptions that were used in the optimizing model and perhaps to suggest ways in which those assumptions can be made more realistic.

In the REM methodology, no explicit probabilistic model is incorporated. One effect of this is to reduce the need for gas turbines in the optimal capacity mix since a primary function of these units is to cover forced outages. Also, the generation expansion planning in REM does not use information derived from system performance simulations to check the reasonableness of the assumed usage factors. As a result, the REM planning process uses exogenously specified usage factors that may not be at all consistent with what the planners could expect to achieve in practice.

At each point in time, the REM optimizer operates as if the utilities were designing a "start-from-scratch" system. If some types of plants are overbuilt in the existing system compared to the start-from-scratch optimum, it is assumed that the excess capacity in one type of plant can be substituted for the needed additions to capacity in another type of plant. This point is made most clearly with an example. Suppose, compared to the start-from-scratch optimum, existing coal plants exceed the optimum amount of capacity. This extra amount of coal capacity will displace some of the gas and oil-fired plants that the "optimum" would want built. It would seem more reasonable to restrict the substitution process to plant types with similar operating characteristics, such as baseloaded coal for baseloaded nuclear.

The logic used to determine the additions to capacity needed over the intermediate planning horizons implicitly assumes that usage of nuclear plants can be adjusted to "follow" the shape of the load curve. This follows from the fact that the shape of the load duration curve is exogenously specified and is the same for all planning horizons. The assumed load duration curve used in the planning process never changes its shape, only its magnitude. Thus, over the intermediate planning horizon (5 years) when the capacities of the nuclear and hydro units are subtracted from the load duration curve, they are effectively treated as covering blocks of electricity that are directly proportional to the total load curve shape. This essentially means the nuclear units being built are credited with significant load-following capabilities once they get on-line. One effect of this will be to bias the expansion planning toward nuclear units.

An important characteristic of the dynamics of the expansion planning process in REM is that the model responds to all changes in inputs as if they were "surprises." REM cannot now be used directly to investigate system anticipations of expected or regulated changes in the future. REM responds only to a linear extrapolation of a weighted average of past information on demand, costs, etc. ALPHA, the weighting factor used in this extrapolation, thus plays a key role in the structure of REM. It can, for example, mimic a very conservatively responding system by assigning heavy weights to data from the distant past. ALPHA acts as a means of speeding up or slowing down the dynamics of the entire system.

Also, by looking only at the particular year for which a decision must be made, with no regard for the year ahead or behind, the logic in

REM has the potential for leading the expansion strategies into "traps." In actuality, a utility decision maker would probably forecast the whole future period before making any decisions. A further difficulty is that the expansion plans in REM cannot be changed once the initial commitment has been made. This holds even under conditions in which the planning projections turn out to be grossly in error.

The present structure of REM generally limits the number of plant types being modeled to just one type for each kind of fuel, with the partial exception of nuclear facilities. Thus, for example, there is just one model for all coal-fired facilities. This single technology then must serve for all coal-fired plants and provides the only measure of the investment cost, operating and maintenance cost, heat rate, availability, and so on. If these data in REM represent the national averages, a problem occurs because a "national average" coal plant model would then be the only type of coal plant available to the generation expansion routine. Since a national average coal plant would include data from a substantial number of older, less efficient plants, it would offer little viable competition to a "national average" nuclear plant, which would include only relatively new plants. The restricted range of available generation technologies in REM represents a major limitation on the applicability of the model. This problem is exacerbated by the fact that storage technologies, such as pumped storage, are not included at all.

In determining capacity expansion requirements, REM takes into account the retirement of existing plants. However, retirement is not determined on economic grounds; it occurs at the end of 40 years for all plant types. While it would be preferable to have retirement responsive to changes in operating costs, the retirement ages should depend upon plant type. For example, setting the retirement age at 40 years for all plants makes the gas turbines look far better than they have a right to look, since they do in fact "wear out" much faster than baseloaded plants such as LWR's.

Expansion planning in REM does not take into account the serious environmental, siting, right-of-way, and resource limitation problems currently confronting many utilities. The omission of these factors, and in particular the lack of siting and right-of-way constraints, may introduce biases in favor of nuclear facilities. This bias is likely to increase over time, since the "dispersed" scenario offered by gas turbines, with reduced siting and transmission problems, is already looking attractive in many areas when compared to the best "centralized" strategies.

Transmission and Distribution

The transmission and distribution (T&D) model does not directly analyze the decision processes governing the investments in T&D equipment. Instead, deterministic relationships are used to estimate the T&D investment in six different categories of equipment as a function of the characteristics of the service area, the number of customers, and the demand configuration in each region. The operation and maintenance costs of the T&D system in REM are estimated using similar relationships. The precise relationships used in the T&D model are estimated statistically from historical data through regression analysis.

The actual planning and construction of transmission and distribution systems is a complex process that trades off costs (capital, operating, etc.) against reliability (line, transformer, load change capabilities, system stability, etc.) in the context of environmental concerns (right-of-way availability, siting, etc.). In general, voltage levels are increasing to give more power transfer per dollar and per right-of-way area. There is continual pressure to put lines underground, with an associated increase in costs. New technologies are being introduced and their potential availability is likely to affect present and future plant siting decisions.

For a given utility, the planning of the transmission and distribution system is usually done by separate departments within the utility. A third level, such as subtransmission, may even be inserted between the transmission and distribution categories. In most cases, EHV transmission planning is closely coordinated with neighboring utilities. Projected plans to 1980 and 1990 are often made, and forecasts have to consider the spatial composition as well as the magnitude of future loads. The planning is typically done by teams of engineers who combine human judgment with the output from a variety of highly specialized engineering computer codes.

Transmission and distribution planning is dependent on the type of generation that is being planned. New exotic technologies (solar, wind, storage, etc.) could have a major impact on transmission and distribution requirements. This is also true of certain types of load management schemes presently being discussed or implemented. In some cases, transmission problems impose constraints that affect the choice of generation types.

Ideally, REM should treat transmission and distribution in an analogous fashion to capacity expansion and generation, i.e., have a T&D expansion submodel and a separate T&D operating cost submodel. The actual T&D submodel estimates both equipment requirements and operating costs through econometrically derived equations involving factors measured only in the current period. The investment decisions in the generation expansion model use projected values for the relevant variables and explicitly recognize the lead times for different types of generating plants. Neither expectations nor lead times are incorporated in the T&D model, even though lead times on construction of new EHV transmission lines are similar to lead times for large fossil and nuclear plants, and distribution system lead times are similar to those of gas turbines. Similarly, the effect of the already existing or committed transmission distribution system is not incorporated.

Equation (1) in Table 3.14 yields transmission structure miles aggregated over voltage levels 69KV and above. This number is then multiplied by dollar costs per structure mile (again, aggregated over voltage levels 69KV and above) to yield costs. A basic problem with this voltage level aggregation approach is that the power-carrying capability of transmission lines varies approximately as the square of the voltage level, while cost per mile is roughly linear with voltage level. Thus, the submodel's structure ignores certain important aspects of how the real world responds to changes in demand. The multiplication of voltage-level-aggregated structure miles times voltage-level-aggregated costs per structure mile may produce reasonable base case results, although, because voltage levels are continuously increasing with increasing demand, there will be some tendency to overpredict costs. The voltage level aggregation should not have a major impact on policy studies that do not have a direct bearing on transmission issues. However, since structure miles is a separate internal variable, one might be tempted to perform policy sensitivity studies that bear directly on the transmission system as, for example, by changing the cost of a structure mile. Such studies would, in most instances, be an invalid application of the model.

The use of linear relationships in the T&D model is also subject to serious question. Since the parameters of the transmission distribution submodel are estimated from only a six-year span of data (1965-1971), it is not surprising that the linear structure can give a good fit in a statistical sense. But it is equally obvious that the linear structure obtained from so few years of data is not necessarily valid for extrapolation some 20 to 30 years into the future. On the basis of previous studies, we believe exponential or log-linear equations would offer a more appropriate structural form. The REM documentation does not provide a satisfactory discussion of this issue which supports the choice of a linear function.

REM Transmission and Distribution Model

ESTIMATED RELATIONSHIPS FOR TRANSMISSION AND DISTRIBUTION EQUIPMENT NEEDS (t-STATISTICS IN PARENTHESES)

TRANSMISSION

(1) $SMT = \underset{(3.01)}{813.2} + \underset{(19.2)}{0.1436}\ EST - \underset{(-3.35)}{556.4}\ LD + \underset{(15.4)}{0.0603}\ AREA$ $\quad R^2 = 0.24$

(2) $SKVAT = \underset{(2.20)}{6.75 \times 10^5} + \underset{(19.8)}{712.5}\ ESRC + \underset{(12.4)}{523.2}\ ESLLP$ $\quad R^2 = 0.91$

DISTRIBUTION

(3) $POLE = \underset{(9.24)}{2.83 \times 10^4} + \underset{(19.8)}{0.9102}\ ESRC - \underset{(-4.03)}{3.43 \times 10^4}\ LD$ $\quad R^2 = 0.98$

(4) $SKVAD = \underset{(40.2)}{435.4}\ ESRC + \underset{(2.47)}{9.46}\ AREA$ $\quad R^2 = 0.83$

(5) $LTKVAD = \underset{(32.6)}{563.2}\ ESRC + \underset{(5.09)}{102.6}\ ESLLP + \underset{(2.82)}{5.14}\ AREA$ $\quad R^2 = 0.94$

(6) $NMD = \underset{(77.3)}{1.005}\ NRCC + \underset{(9.1)}{14.0}\ NLLPC + \underset{(2.57)}{7.28}\ NPUBC$ $\quad R^2 = 0.99$

SMT = TRANSMISSION REQUIREMENTS (STRUCTURE MILES)
SKVAT = SUBSTATION REQUIREMENTS AT THE TRANSMISSION LEVEL (KVA)
SKVAD = SUBSTATION REQUIREMENTS AT DISTRIBUTION LEVEL (KVA)
LTDVAD = LINE TRANSFORMER REQUIREMENTS (KVA)
NMD = METER REQUIREMENTS (NUMBER)
POLE = PRIMARY DISTRIBUTION REQUIREMENTS (POLE MILES)
EST = TOTAL ENERGY SALES (kwhrs. IN MILLIONS, MMKwhs.)
LD = LOAD DENSITY (MILLIONS OF Kwhrs. PER SQUARE MILE)
AREA = GEOGRAPHIC AREA (SQUARE MILES)
ESRC = ENERGY SALES TO RESIDENTIAL AND COMMERCIAL CUSTOMERS (MMKwhs.)
ESLLP = ENERGY SALES TO LARGE LIGHT AND POWER CUSTOMERS (MMKwhs.)
NRCC = NUMBER OF RESIDENTIAL AND COMMERCIAL CUSTOMERS
NLLPC = NUMBER OF LARGE LIGHT AND POWER CUSTOMERS
NPUBC = NUMBER OF PUBLIC AUTHORITIES CUSTOMERS.

ESTIMATED RELATIONSHIPS FOR TRANSMISSION AND DISTRIBUTION OPERATION AND MAINTENANCE COSTS (t-STATISTICS IN PARENTHESES)

$OMT = \underset{(6.53)}{1.75}\ NRCC + \underset{(6.33)}{199.1}\ ESRC + \underset{(4.78)}{92.11}\ ESLLP$ $\quad R^2 = 0.90$

$OMD = \underset{(89.2)}{18.80}\ NRCC + \underset{(3.65)}{159.8}\ NLLPC$ $\quad R^2 = 0.97$

$OMG = \underset{(66.9)}{26.05}\ NRCC + \underset{(11.2)}{903.3}\ NLLPC$ $\quad R^2 = 0.96$

OMT = OPERATION AND MAINTENANCE EXPENDITURES FOR TRANSMISSION (IN 1967 DOLLARS)

OMD = OPERATION AND MAINTENANCE EXPENDITURES FOR DISTRIBUTION (IN 1967 DOLLARS)

OMG = GENERAL AND ADMINISTRATIVE OVERHEAD EXPENSES (IN 1967 DOLLARS)

Source: [4]

A variety of issues has been raised that question the validity of certain aspects of the T&D model. In most cases, they stem from the fact that the model structure is overly simplifed. There are simply many aspects of transmission and distribution planning and investment that are not included in the model. However, more study is needed to provide explicit opinions on the importance of these issues. It remains possible that the T&D component's input-output behavior is reasonable and appropriate for many studies, even though it is highly simplifed.

Nuclear Fuel Cycle

The function of the nuclear fuel cycle component within REM is to compute the current and predicted costs of building and operating nuclear reactors. The model includes the following four types of nuclear units: light water reactor field with uranium (LWR); LWR fueled with plutonium (LWRPU); liquid metal fast breeder reactor (LMFBR); and high temperature gas reactor fueled with thorium (HTGR). Some of the more important features of the nuclear fuel cycle model are:

- Use of uranium supply schedules or fixed availability to determine cost of yellowcake.
- Calculation of enrichment costs, including conversion to uranium hexafluoride, and requirements for separative work. The latter step involves determining the optimum tails assay, given costs of uranium, conversion, and separative work.
- Valuation of spent fuel based on the costs of recycling with credits for the value of plutonium valued in such a way as to equate the costs of a uranium and a plutonium fuel loading.
- Calculation of HTGR fuel costs based upon a simplified version of the methods for the LWR, without considering recycling.
- An explicit fuels management algorithm that accounts for initial fuel loadings, burnup of fuel, shipping and storage charges, and so on.

While an assessment of the technical validity of the details of the nuclear fuel cycle model is outside the scope of the present project, it generally seems to be correctly formulated and implemented. Further, the attention to the details of fuels management is impressive. Since the model has been used in analyzing a number of scenarios relating to the availability of uranium, the timing of LMFBR penetration, and the general development of the nuclear industry, it is especially important to properly account for the interactions between uranium- and plutonium-fueled reactors. That the HTGR thorium-fueled reactor is not considered in more detail and that only one breeder type is considered do not seem serious problems given the state of these technologies. If the time horizon of the model were to be extended significantly, these issues would become more important.

Load Prediction and Exogenous Factor Forecasts

The remaining two modules in the supply submodel, as shown in Figure 3.2, deal with the process by which utilities form expectations regarding the future values of certain key inputs to the planning process. The authors give the following description of the procedure used to simulate how utilities make predictions of future load curves:

> While the model incorporates a set of econometric demand equations to generate actual demand given a vector of prices of all basic energy inputs -- coal, oil, natural gas, and the endogenous electricity price -- we do not assume that the electric utilities imply such a sophisticated analysis of the own-price and cross-price elasticities to project demand. Rather, we believe that electric utilities are considerably more naive. We specify their projections of demand by exponentially weighted moving averages with a trend adjustment ([33], p. 8).

The relationships used in REM to implement this procedure are as follows: Define

$t = 1, 2, \ldots,$ in six-month steps,

V_t = Energy demand at time t as obtained from demand submodel,

$P_{t_0} + z$ = Predicted energy demand at time $t_0 + z$, where z corresponds to the three planning horisons of 2-1/2 years (z = 5), 5 years (z = 10), and 10 years (z = 20).

Then the prediction equation is:

$$P_{t_0} + z = E_{t_0} + T_{t_0}$$

where:

E_{t_0} = smooth and trend-adjusted current value,

T_{t_0} = smoothed current trend.

E_t and T_t are defined by the following relations:

$$T_t = (1 - \alpha)T_{t-1} + F_t - F_{t-1})$$

$$E_t = (\frac{1 - \alpha}{\alpha})T_t$$

where F_t is defined as

$$F_t = (1 - \alpha)F_{t-1} + V_t$$

The value used for α in the basic simulation is reported as 0.4.

Although electric utility practice in forecasting future demands varies widely from utility to utility, in general relatively sophisticated techniques are being used and the trend presently is for rapid introduction of ever more sophisticated methodologies. The "naive" techniques used in the REM load prediction modules do not seem to accurately represent the actual situation. The accuracy of the model structure will decrease even further in the future as utilities continue to improve their load forecasting capabilities. It should also be noted that the widespread use of sophisticated prediction techniques is a relatively recent occurrence. Therefore, even if the relatively naive load prediction model in REM can be adjusted to match the historical data, it may still be inappropriate for use in the future.

The trend extrapolation procedures used in the load prediction module are not well designed to handle sudden shifts in demand levels. This limits the ability of using REM to analyze policies or exogenous changes that are likely to result in sharp movements in electricity demand levels. The load prediction in REM will be affected only gradually and after some lag, even though the shift may immediately be regarded as permanent.

The load prediction model provides a point forecast of future demands, while today many utilities make interval forecasts; that is, they specify a range of possible future demands, or demand scenarios. Interval forecasts are important techniques by which utilities introduce explicit consideration of uncertainty in the generation expanion planning process. Of course, if the load prediction model were changed to produce an interval forecast, that would be useful only if the generation expansion model were also extended to utilize that information.

In predicting future load curves, the shape of the load duration curve is an exogenous input. It is tempting to try to study the effects of various policy actions, such as peak load pricing, by doing separate studies on how they will affect the load duration curve and then changing the REM exogenous inputs accordingly. However, this is appropriate only if the shape of the future load duration curve can be regarded as independent of the predicted changes in the level and composition of demand. In general, this assumption is not valid, since changes in demands will alter the shape of the load duration curve. Therefore, when policy actions are introduced into REM by changing the shape of the load duration curve, it must also be argued that these changes are consistent with the new patterns of electricity demands predicted by the model. This problem could, in principle, be dealt with by making the shape of the load duration curve endogenously determined and responsive to changes in the pattern of demands. However, it would probably require a major research effort to make this change in the structure of REM.

In addition to the predicted load curves, the generation expansion model requires forecasts for all of the exogenous factors that influence future generation costs. These include most importantly fuel and construction costs, and plant operating characteristics. The modelers implement many of their policy scenarios by changing these exogenous inputs. However, according to [34] -- and confirmed by analysis of the computer code -- the prediction of future values, whether for demand or for exogenous factors, is done by trend extrapolaton of past values. The difference between extrapolated demand and exogenous variables is the way in which the actual, rather than the expected, values are computed in REM. The actual values for demand are estimated from the structural relationships in the demand submodel, while the actual values for the exogenous factors are, by definition, exogenously specified.

This implies that REM can be appropriately used to study the impacts of changes in the actual values of the exogenous factors, but it can be used only indirectly, at best, to study the effects of changes in the expectations concerning future values for those factors. An exogenously specified change in the actual values will eventually affect expectations through the trend extrapolation procedures in the forecasting model, but a user of REM cannot directly specify a change in the expectations themselves.

To see how this would work in practice, suppose that in 1977 it is expected that coal prices will start to fall sharply in 1987. This information can be supplied to REM by changing the exogenously specified coal price. The coal prices used by the demand and electricity generation models will follow the specified patterns. The situation in the generation expansion model is quite different. There will be no change in expansion plans prior to 1987. The expansion plans will gradually begin to respond to the change from 1987 on. There will be no effect on the installed capacity of coal plants until at least 1992, and no effect on the installed capacity of nuclear plants until 1997. Clearly, it would be desirable to have a user directly specify the fuel price expectations used in the generation expansion model instead of simply having them respond to past values. This does not appear to be a difficult structural change and would extend the applicability of REM.

3.4.4 Design of the simulation experiments

The overview assessment of the supply submodel has identified a number of areas in which the simplifying assumptions used in constructing the model impose limitations on its applicability. In some instances, the nature and extent of the limitation are apparent from the basic structure of the model. Most limiting factors mentioned in the overview will, however, have effects whose significance cannot be judged solely on theoretical grounds. The magnitude of these effects will be determined by such things as the values assigned to the model's parameters, the interactions among the components of the model, and the state of the world in which the electric power system is presumed to be operating. The significance of the effects will also be influenced by the policy issues to which the model is applied.

The function of the in-depth analysis of the supply submodel is to perform experiments that will provide quantitative information about the impacts of the key limiting factors. The experiments, which will be outlined below and discussed in detail in the following section, focus on the model components dealing with electricity generation, generation expansion, and forecasting procedures. Neither transmission and distribution nor the nuclear fuel cycle are dealt with directly in the in-depth experiments. The T&D model plays a useful role in the overall REM structure, but it is so highly simplified that it has to be regarded as a "placeholder" model. It clearly should not be used to analyze detailed T&D decisions. The nuclear fuel cycle component is quite large and has been evaluated elsewhere. It was felt that detailed analysis of its substantive content would be a major undertaking that would absorb excessive amounts of resources and was not really central to the objectives of the assessment project. It seemed more important and more productive to concentrate the in-depth analysis on the other three components of the supply submodel.

The simulation experiments dealing with the supply submodel fall into the following categories:

- o Alternative generation technologies,
- o Capacity factors and maintenance scheduling,
- o Forecasting procedures,
- o Shape of the load duration curve,
- o Plant retirement ages,
- o Lead times,
- o Reserve margin, and
- o Fuel, operating, and investment costs.

Alternative Generation Technologies: One of the problems identified in the overview assessment was the very limited number of plant types or technologies available to the generation expansion planning process in REM. To test the effect of this limitation, one would at the very least like to set up an experiment where there were two types of coal plants and two types of nuclear plants. The first type would be the national average plant that would be used for simulating the current generation mix in operating the electric power system. The second type would represent the state-of-the-art plant for that fuel type and would be the plant type that is really involved in the generation expansion decisions. Unfortunately, the structure of REM does not facilitate the introduction of additional plant types. Conceptually it should be an easy task, but in practice almost every subroutine would be affected in some way. As a rough approximation to this experiment, the uranium-fueled light water reactor was left as it was, but the single slot for the coal-fired plant was changed to represent a 1985-1990 state-of-the-art, baseloaded, coal-fired facility. A second experiment focused on the introduction of advanced nuclear plants by making their operating characteristics more competitive with LWRs. The final experiment in this set altered the rate at which the system is allowed to introduce LWRs.

Capacity Factors and Maintenance Scheduling: The next set of experiments examines the impact of the availability factors on base case validity and the sensitivity of the model to changes and uncertainties in those factors. REM separates the availability factor into two components: (a) the availability that would result if there were no forced outages, called the duty cycle (DUTMAX), and (b) the availability that would result given no planned outages, confusingly called the availability factor (AVAFAC). To avoid ambiguity, the product of these two is here called the capacity factor. To assess the impacts of alternative assumptions concerning the scheduling of maintenance, an experiment is run in which the duty cycle is increased while the availability factor is reduced by an offsetting amount. The capacity factor, being the product of the duty cycle and the availability factor, is thus held the same as in the base case. Other experiments are then carried out to see how sensitive the REM results are to changes in the capacity factor for LWRs. In addition, as pointed out in the overview, there is some reason to think that the capacity factors used in REM are quite optimistic. To evaluate the possible significance of this, an experiment is run in which all the capacity factors are reduced to levels consistent with current practice.

Forecasting Procedures: An area of serious concern involves the methodology and parameters used in the forecasting routine. At each point in time, this routine uses linear extrapolations of past data to project future values for electricity demands, capital costs, return on equity, fuel costs, heat rates, operating and maintenance costs, and usage factors. If the electric power system is in fact growing exponentially, the linear extrapolations will seriously and persistently underpredict future values. The first experiment in this set modifies the forecasting routine to incorporate exponential extrapolation procedures. The other experiments carry out sensitivity analysis on the extrapolation parameter, ALPHA, which determines how much weight is given to recent data points as opposed to data points in the more distant past.

Shape of the Load Duration Curve: It was pointed out in the overview that the shape of the load duration curve, although it is a exogenous input to REM, will be affected by such things as storage technologies, pricing policies, and conservation policies. It would also be affected by the introduction of probabilistic effects in the planning process. The sensitivity of the REM results is tested by varying the shape of the load duration curve over a range of plausible configuratons.

<u>Plant Retirement Ages</u>: It is clear that it is inappropriate to assume, as REM does, that all types of plants have the same retirement age. It is not clear how quantitatively significant the problem is. Unfortunately, it is not feasible, without making major structural changes, to conduct experiments in which the retirement ages are allowed to differ among the different types of plants. The only experiment that was practical was to make simultaneous changes in the retirement ages of all plants. This will test the model's general sensitivity to retirement age, although it will not provide direct information on the effects of plant-specific retirement ages.

<u>Lead Times</u>: Several simulations were performed to study the effect in REM of changing the lead times for both nuclear and coal plants. Because of the way REM is programmed, it is difficult to reduce nuclear lead times to less than eight years or to give coal plants as long a lead time as nuclear.

<u>Reserve Margin</u>: The overcapacity factor used in REM implicitly incorporates the system reserve margin used in planning. Experiments were run in which the overcapacity factor is changed by $\pm$ 25 percent to see how the simulated system responds to different reserve margins.

<u>Fuel, Operating, and Investment Costs</u>: The next set of REM runs involved systematic sensitivity testing of the REM response to variations in fuel prices, operating costs, and the investment costs of new facilities. It

was relatively easy to make changes in coal, oil, and gas prices that were accurately reflected in plant operating costs. Nuclear fuel prices were more difficult to assess because changes in yellowcake prices are transformed by the time they entered the nuclear fuel market calculations. Therefore, nuclear price changes were introduced by directly altering the operating and maintenance costs for nuclear plants.

3.4.4 In-depth assessment

Much of the analysis throughout this section will be based on a comparison of the outputs from the simulation experiments with the REM base case results. For reference, some of the key supply outputs from the base case are summarized in Table 3.15. Since a number of the experiments are designed to examine some of the underlying base case assumptions, an evaluation of the base case is not given separately but is included as part of the findings from the simulation experiments.

Alternative Generation Technologies

Since it was not possible to introduce additional technologies, the characteristics of the single type of coal-fired plant were changed to represent a more advanced technology. This was approximated by lowering the coal-fired plant's heat rate by 10 percent to 9,000 Btu/kwh, reducing the operating and maintenance costs, and increasing the investment cost by 10 percent. Table 3.16 shows the substantial effect this hypothetical state-of-the-art coal plant has on the eventual (1997) split between nuclear and coal installed capacities. It is apparent that, given the choice between the average (relatively old) coal plant and the average (relatively new) nuclear unit, the base case generation expansion heavily favored nuclear. When the baseloaded coal plant is introduced to compete with LWR's, the installed nuclear capacity in 1997 is one-third lower than in the base case projection. This increased competition between the baseloaded coal and nuclear plants has essentially no impact on the installed capacity of other types of plants.

Another experiment involving new technologies focused on the introduction of advanced nuclear plants. Advanced nuclear technologies are not competitive with LWRs in the REM base case because their capacity factors are set well below the LWR capacity factors. When the advanced nuclear technologies are given the same capacity factors as LWRs, they do enter into the capacity expansion plans. Taking the REM results for the South Atlantic region as an example, by 1997 the installed nuclear capacity projections are as shown in Table 3.17.

It is apparent that the REM results are very sensitive to changes in the technologies available to the expansion planning process. There is a need to make a wider range of technologies available if the REM analysis is to be more generally applicable. A list of desirable additional options that have been identified in the course of the assessment project include:

- an outmoded coal-fired facility, to be dropped gradually over the nearer future,
- state-of-the-art baseloaded coal choice,
- state-of-the-art intermediate coal choice,
- a 1990 characteristic advanced coal-fired facility, perhaps atmospheric fluidized bed, and

Table 3.15

REM Base Case Summary of Supply Results

		1975	1980	1985	1990	1995	1997
Elect Energy Demand MMWH		1878.4	2433.0	3106.8	3819.2	4673.1	5080.2
Peak Power Demand GW		352.3	460.2	590.7	762.2	888.6	966.8
Installed Capacity-GW	Coal	195.3	253.4	323.2	398.9	429.8	448.1
	Gas	113.2	104.4	93.4	81.4	69.2	64.5
	Oil	49.3	47.5	43.3	38.3	32.8	30.6
	LWRU	43.1	81.8	140.2	246.9	361.5	415.9
	I.C.	43.4	45.3	57.6	57.0	67.6	74.9
	Total	512.7	611.6	746.7	921.3	1069.3	1147.1
Electricity Generation-MMWH	Coal	912.4	1194.3	1427.9	1588.4	1672.6	1699.2
	Gas	312.2	237.1	253.2	103.0	43.3	38.9
	Oil	57.5	89.4	109.6	22.6	7.3	24.5
	LWRU	276.2	532.5	898.1	1642.5	2443.0	2792.4
	I.C.	5.6	15.2	9.4	11.5	14.2	16.1
Usage Factors	Coal	.533	.538	.504	.455	.444	.433
	Gas	.315	.259	.309	.144	.071	.069
	Oil	.133	.215	.289	.068	.026	.091
	LWRU	.731	.743	.731	.759	.771	.766
	I.C.	.015	.038	.019	.023	.024	.025
	Total	.418	.454	.475	.473	.499	.506
Cost of Elect M/KWH		26.7	35.1	46.4	60.7	79.5	89.5
US Cap Invest-bill$		152.6	246.9	419.9	756.1	1232.4	1527.6
Total Demand Energy 10^{17}/BTU		.301	.293	.300	.323	.359	.377
Total Assets bill $		171.0	290.5	501.4	878.2	1414.0	1775.2
Oper & Main Exp - bill $		24,2	41.7	69.7	99.4	152.6	186.2

* all values truncated rather than rounded

Table 3.16

Introduction of Advanced Coal Plant

	Installed Generation Capacity in 1997 (GW)	
Type of Plant	Base Case	Advanced Coal
Coal	448	660
LWR	416	260
Gas	65	65
Oil	31	29
I.C.	75	67

Table 3.17

Impact of Equal Capacity Factors for All Nuclear Technologies

Plant Type	Installed 1997 Capacity (GW) in South Atlantic Region	
	Base Case	Experiment with all nuclear capacity factors equal
LWR - uranium	225	54
LWR - plutonium	0	0
HTGR	0	20
LMFBR	0	117

- state-of-the-art light water reactor with uranium fuel.

In calibrating the model to replicate the historical patterns, the authors imposed an aribitrary restriction on the rate at which the system could introduce nuclear units. The purpose was to keep nuclear capacity from growing at "unreasonably" rapid rates. When this constraint is removed, the REM results show a drastic increase in nuclear capacity, and a corresponding decrease in coal capacity, during the projection period as well as in the earlier years. In addition, the elimination of the constraint produces some oscillations in nuclear capacity that were not present in the base projections (see Figure 3.10). Although a different manner of releasing the constraint has verified that the oscillations occur, we have not developed an explanation for them.

This artificial constraint is, however, not necessarily an inappropriate modeling procedure. An alternative approach might have been to assign additional implicit or "shadow" costs to the investment in these new technologies to reflect the associated uncertainties and start-up problems. Determination of the appropriate levels of such cost penalties would, however, be quite difficult and would typically be only partially transferrable to other newly introduced technologies. The fact that artificial constraints have been imposed on the REM base case so it duplicates the past history of nuclear growth does mean that the successful replication of history provides no test of the model's validity.

Capacity Factors and Maintenance Scheduling

The first experiment in this set changed the duty cycle and availability factors by offsetting amounts in order to test the effects

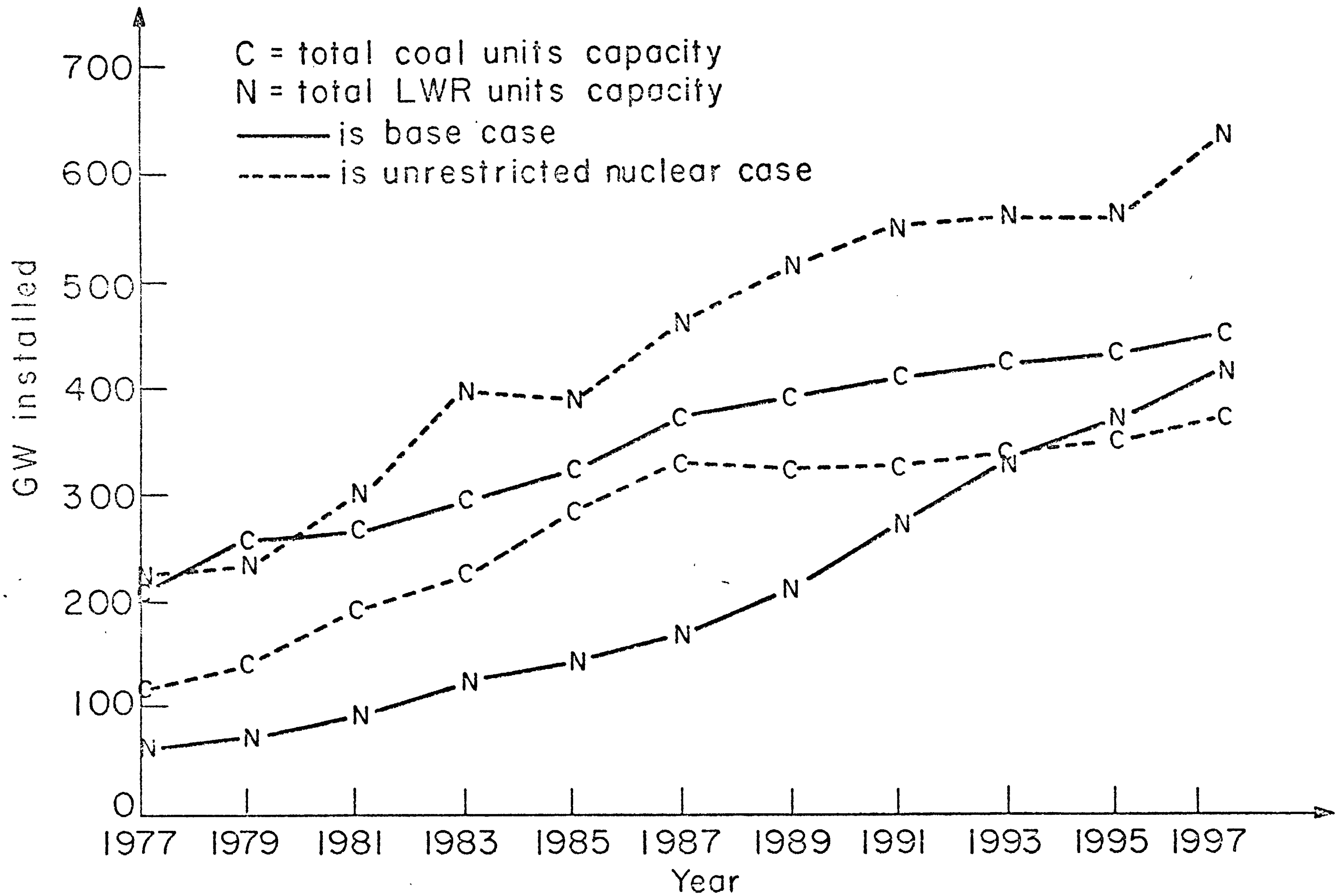


FIGURE 3.10 COMPARISON OF BASE CASE WITH UNRESTRICTED GROWTH OF NUCLEAR CAPACITY

of assuming that maintenance is scheduled uniformly throughout the year. That test was never accomplished because the results of the experiment were dominated by a critical, pervasive, and quite unexpected characteristic of REM. As shown by the data in Table 3.18, the capacity factor for nuclear facilities reaches 87 percent in 1985, a rate of utilization that is surely unattainable in practice. That is the average usage factor for the country as a whole -- in some regions it exceeds 90 percent. This occurs despite the fact that the maximum capacity factor had been exogenously specified to be 73 percent.

The explanation for this is found in a portion of the computer code that states in effect, if total effective capacity in a region (i.e., installed capacity derated by the availability factor) is less than demand, set the LWR availability factor in that region to whatever value is needed to overcome the deficit. Our information, from a conversation with the modelers, is that this was done to prevent the model results from being interpreted as predicting electricity shortages in a particular area at a particular time. Unfortunately, the method used to deal with this perceived problem, arbitrarily raising the utilization of LWRs enough to meet the entire deficit, can push the nuclear usage factor to levels that are clearly unattainable in practice. Furthermore, since this increase in nuclear usage factors is part of the internal logic of the electricity generation model, the unsuspecting user has no way of knowing when or if he is imposing an effective constraint on the maximum capacity factors for LWRs. The limit on LWR capacity factors as specified by the user is simply overridden by the logic of the computer program. The nature and even the existence of this procedure is not mentioned anywhere in the available documentation.

Table 3.18

Impact on Nuclear Usage Factors of Offsetting Changes in the Duty Cycle and Availability Factors

	1980	1985	1990	1997
Nuclear Installed Capacity (GW)				
Base Case	82	140	247	416
Duty Cycle/Availability Experiment	87	147	252	413
Nuclear Generation (MMWH)				
Base Case	533	898	1643	2792
Duty Cycle/Availability Experiment	575	1118	1863	2845
Nuclear Usage Factor (percent)				
Base Case	74	73	76	77
Duty Cycle/Availability Experiment	75	87	84	79

The sensitivity of the REM results was further tested by assigning values of 0.67, 0.60, and 0.50 to the maximum capacity factor for LWR's (the base case value for this factor was 0.73). The results, as summarized in Table 3.19, show REM to be acutely sensitive to the capacity factor. Installed capacity and generation in nuclear plants drop sharply, much more rapidly than the totals, as the capacity factor is reduced. With the maximum nuclear capacity factor set at 0.50, nuclear plants supply only 8 percent of total electricity generation, compared to 55 percent in the base case. It should be noted that in all of the experiments, as well as in the base case, the nuclear usage factor observed in the REM results exceeded the specified maximum value.

The extreme sensitivity to changes in the capacity factor is not necessarily a flaw in REM; indeed, this may be a reasonable response. It does, however, emphasize the need for paying careful attention to the values assigned to the capacity factors. A user should estimate these factors as accurately as possible and should then perform sensitivity studies within the band of uncertainty that still exists.

The capacity factors used in the REM base case are appreciably higher than they are likely to achieve in the future. As alternative estimates we have substituted some current practice results taken from Commonwealth Edison's 1975 Annual Report. These figures represent the latest actual data from a company which is considered "state of the art" in its operating techniques. The annual capacity factors reported by them are:

Coal	0.6
Gas	0.75
Oil	0.75
Nuclear	0.58

Table 3.19

Impact of Alternative Maximum Capacity Factors for Nuclear Plants, 1997 Results

	Maximum Capacity Factors for Nuclear Plants			
Base Case	0.73	0.67	0.60	0.50
Installed Capacity (GW)	1147	1148	1128	1049
Nuclear	416	335	233	68
Coal	448	527	611	722
Electricity Generation (MMWH)	5080	4900	4727	4470
Nuclear	2792	2379	1577	357
Coal	1699	1924	2494	3351
Usage Factor				
Nuclear	0.77	0.81	0.77	0.60
Coal	0.43	0.42	0.47	0.53

These were split into planned outage and forced outage components as in the base case, and the run is reported in the second column of Table 3.20. A second experiment was conducted using the same current practice capacity factors but assuming that maintenance was scheduled uniformly throughout the year. This experiment is reported in the last column of Table 3.20.

With the lower capacity factors in the first experiment, the operating cost of the power system rises much faster than the capital cost and the price of electricity is 28 percent above the base case. Nuclear accounts for 19 percent of total capacity by 1997 and 30 percent of electricity generation, compared to 36 percent and 55 percent respectively in the base case. Some power system engineers may find the results of this experiment more "believable" than the base case, given present trends in the industry, especially in nuclear power growth and performance.

Installed capacity and generation in coal-fired plants also declines, but much less rapidly. In sharp contrast to the coal and nuclear units, the other fossil plants show a doubling of installed capacity and a tenfold increase in electricity generation. This response seems reasonable enough, with the fossil peaking and cycling units being used more heavily as a result of the lower capacity factors on the baseloaded plants.

The results of the second experiment are less acceptable. When the current practice values for maximum capacity factors are combined with the assumption of uniform maintenance scheduling, the results seem to indicate a serious instability in REM (see Table 3.20). Nuclear

Table 3.20

Impacts of Current Practice Capacity Factors and Uniform Maintenance Scheduling, 1997 Results

	Base Case	Current Practice Factors	Current Practice Factors and Uniform Maintenance Schedule
Installed Capacity (GW)	1147	963	999
Nuclear	416	180	138
Coal	448	302	381
Other Fossil	170	369	367
Electricity Generation (MMWH)	5080	4024	4415
Nuclear	2792	1209	1199
Coal	1699	1444	2075
Other Fossil	80	885	679
Usage Factors			
Nuclear	0.77	0.77	0.99
Coal	0.43	0.55	0.62
Other Fossil	0.05	0.27	0.21

installed capacity and generation are still further reduced while coal-fired generation increases sharply to make coal the dominant fuel. Yet the scheme of the model is such that nuclear is still baseloaded in the electricity generation routine and because of "shortages" in all regions (i.e., "available" capacity after allowing for outages is not sufficient to meet the load), nuclear is operated with an average capacity factor of 0.99 throughout the nation in 1997 (the maximum specified was 0.58). The price of electricity is lower than in the previous experiment, because LWRs are supplying nearly the same amount of electricity even though there is lower installed capacity of nuclear. This disparity arises from the additional generation supplied by nuclear operating at such a high capacity factor.

This outcome obviously is not realistic. It is a case where variations in the input parameters within seemingly reasonable limits have produced unreasonable results. The problem is a result of the supply-demand imbalances due to the generation expansion logic in REM, combined with the unrealistic method by which REM deals with these imbalances. The reason for the "shortages" is that the linear load prediction model is underpredicting system load (as can be seen from the regional outputs) and this directly results in too small a nuclear capacity. But, in the model, "shortages" are met by operating the nuclear units at impossibly high usage factors, thus reducing operating costs.

Further information on the impact of the REM method for dealing with shortages is given by the results of another EPRI study by R. Taber

Jenkins conducted in parallel with the model assessment project [31]. In that study, experiments were run to compare the REM electricity generation results with the results produced by FORGON, a more detailed system simulator actually used by a major utility (TVA). Some of the key results obtained from this comparison are summarized in Figure 3.10a. Using the basic REM data (and taking the South Atlantic Region as the test case), the FORGON results indicate much higher usage of coal plants and correspondingly lower usage of gas, oil, and internal combustion units.

When the input data are changed to be consistent with the EPRI synthetic system data, the REM results show the same instability that we found in our experiments; the results are shown in the right-hand portion of Figure 3.10a. Jenkins describes the results as follows:

> This simple data change triggered the condition which causes the [REM] simulation to use full plant capacity instead of effective capacity . . . Having a situation where the total effective capacity is less than the peak load, has a devastating effect on the simulation . . . As a result of increasing the nuclear capacity to its installed value, the nuclear energy produced is increased far beyond what could be reasonably expected . . .
>
> This implies that when a utility is short of capacity, it can produce more energy with its most economical equipment. This is untenable, since the savings in system operating cost are so great that the utility would have been doing everything possible to achieve these savings even if it were not short of capacity. [31]

These results are consistent with and support the findings from the experiments conducted in the model assessment project.

Forecasting Procedure

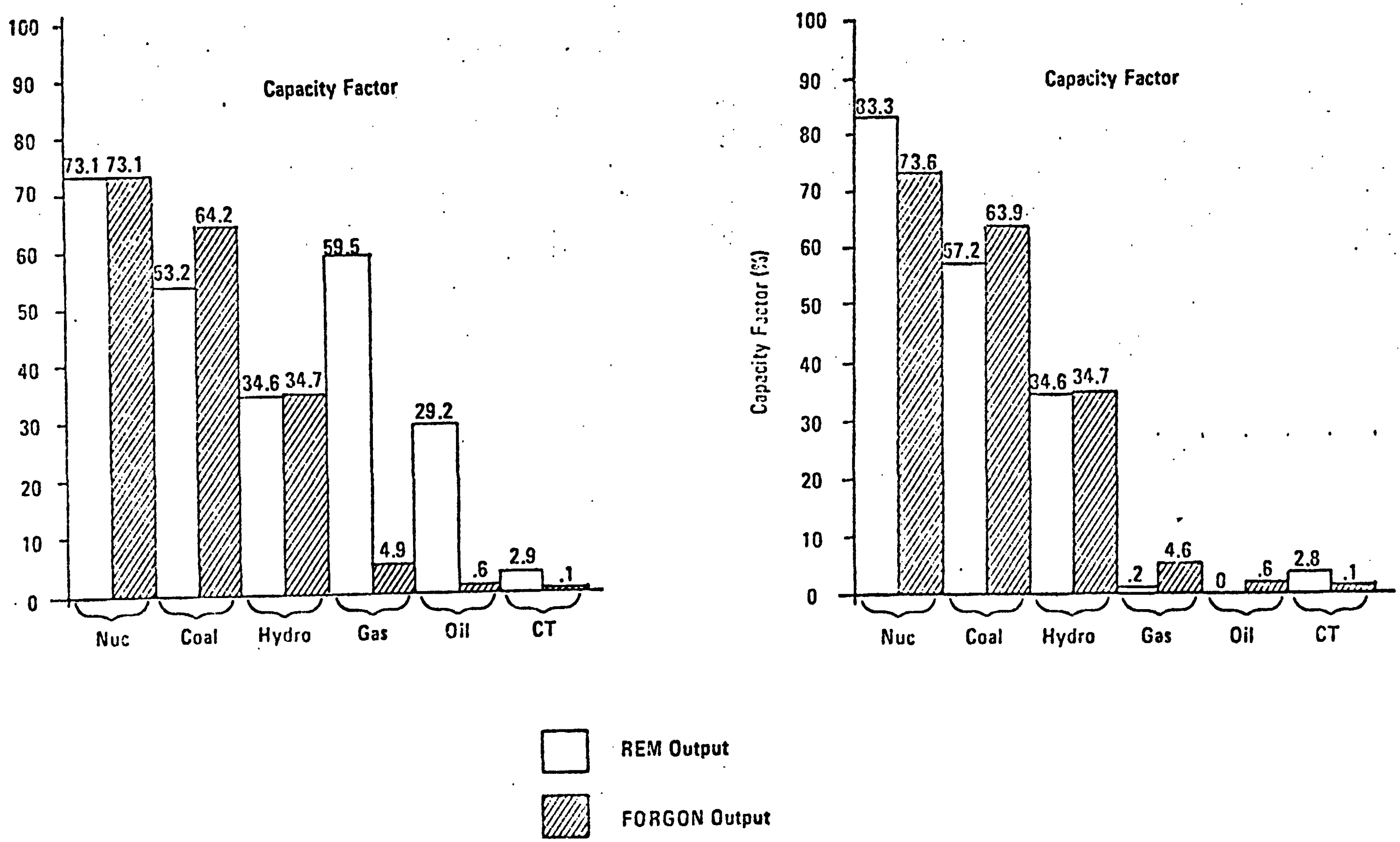
Under conditions of exponential growth, the linear extrapolation procedure used in the REM forecasting routine can seriously underpredict

Figure 3.10a

Comparison of Electricity Generation Results from REM with Results from TVA's FORGON System Simulator

Comparative results of REM and FORGON using original Region 5, REM data for 1985.

Comparative results of REM and FORGON using Region 5, 1985 load forecast and EPRI synthetic system characteristics for the supply system.



future demand levels. Because nuclear facilities have the longest lead times, they can be underbuilt by as much as 50 percent due to this consistent forecasting error. An experiment was run using a forecasting procedure that approximated a "true" exponential forecaster by compounding the linear trends every six months.

As expected, there are substantial increases in nuclear installed capacity (see Table 3.21). These results do not show as large an increase in nuclear as might have been expected, for two reasons:

- The demand curves showed a leveling off in the late 1970's which made the linear predictor quite reasonable into the 1980's;
- Capital, fuel, and operating and maintenance costs also received linear projections which made nuclear facilities appear slightly cheaper.

Other experiments were designed to test the model's sensitivity to changes in ALPHA, the parameter used in the forecasting routine to determine how much weight is given to the most recent data points. If ALPHA is large (close to 1.0), the forecast looks only at the current data, whereas if ALPHA is smaller, the past data takes on greater importance. In the course of conducting these experiments, it was discovered that there are some errors in the way ALPHA is included in the REM programming. The first error is that the initial value for ALPHA is set to 0.10, instead of 0.40 as reported in the documentation. For demand forecasts, however, the ALPHA value is hardwired at 0.40 and for the equity dividend forecasts it is hardwired at 0.30. This means that a user who changes the ALPHA value in the input data set will effect no change in the demand or equity dividend forecasts.

The other error is that a variable used in the nuclear fuel cycle subroutine was also given the name ALPHA. To the computer, the two

Table 3.21

Effect of Various Forecasting Techniques on REM Outputs

	Installed Capacity, 1997 (GW)					Electric Energy Demand (MMWH)
	Coal	Oil	Gas	Nuclear	I.C.	
Linear Forecast, Base Case	448	31	65	416	75	5080
Exponential Demand Forecasts	450	32	69	452	55	5084
All Forecasts Exponential	415	32	68	517	54	5060

ALPHA's are indistinguishable. The nuclear ALPHA happens to be a time-varying function of the capital charge rate and the uranium feed rate; it is this computation that determines the value of ALPHA actually used in the forecasting routine. This computed value for ALPHA typically varies between 0.10 and 0.18 in the REM base case.

The errors in the treatment of ALPHA were corrected and then several experiments were run using different values for ALPHA. As shown in Table 3.22, the demand for electricity, the cost of electricity, and the generation mix are all sensitive to changes in ALPHA. This is a particularly significant finding because it is difficult to conceive of ways to estimate ALPHA accurately. This is another instance in which it is important that careful sensitivity analysis be incorporated in any REM application.

Shape of the Load Duration Curve

There are a number of conceivable developments, such as the use of storage facilities, that could alter the shape of the load duration curve. The incorporation of storage in utility generation expansion strategies would typically involve a complex iterative procedure. In REM, this would require extensive recoding to express the load-duration curves as a function of storage options. There are trade-offs here between complexity and accuracy. The simplest and least accurate approach involves a before-the-fact assessment of storage needs, much like hydro is treated in REM, and an adjustment of the load-duration curve to mimic the situation into which the other plant types are likely

Table 3.22

Effects of Fixing the Errors in ALPHA and the Use of Various ALPHA Values

	Demand ALPHA	Equity ALPHA	All Other ALPHAs	Installed Capacity GW 1997 Coal	LWR	Electric Energy Demand MMWH	Cost of Elect. m/k Wh
Base Case	.400	.300	0.10-0.18	448	416	5080	89.5
	.400	.300	.100	457	404	5027	89.9
	.400	.300	.400	469	342	4937	92.4
	.400	.300	.700	467	325	4908	91.9
	.400	.300	1.000	514	285	4904	93.3
	.100	.100	.100	429	393	4983	90.8
	1.000	1.000	1.000	722	185	4253	101.1

to have to fit. This was the approach taken in the series of experiments reported here.

Several hypothetical changes in the shape of the load duration curve that might be produced by storage devices or other load management policies are illustrated in Figure 3.11. Even the dramatic change in the load duration curve associated with storage devices had relatively little impact on the mix of generation types (see Table 3.23). This is a surprising result, since in the overview assessment it was thought that the shape of the load duration curve was likely to be an important piece of input data.

Plant Retirement Ages

The results of the experiments involving changes in plant retirement ages are not conclusive but do indicate appreciable sensitivity in certain areas. As shown in Table 3.24, lowering the retirement ages for all plants produces significant reductions in the installed capacity of oil, gas, and internal combustion facilities. Though it was not feasible to run experiments making the retirement ages vary with plant type, it is reasonable to infer that the impact on mix would be even greater than that shown in Table 3.24.

It was also infeasible to make retirement age dependent on the operating costs of the different plants. Although this extension was hinted at in the early REM materials, this appears to be a difficult concept to fit into the current REM structure. Making retirement ages vary with plant type could be more easily implemented and the results of the experiments indicate that this would be a useful improvement.

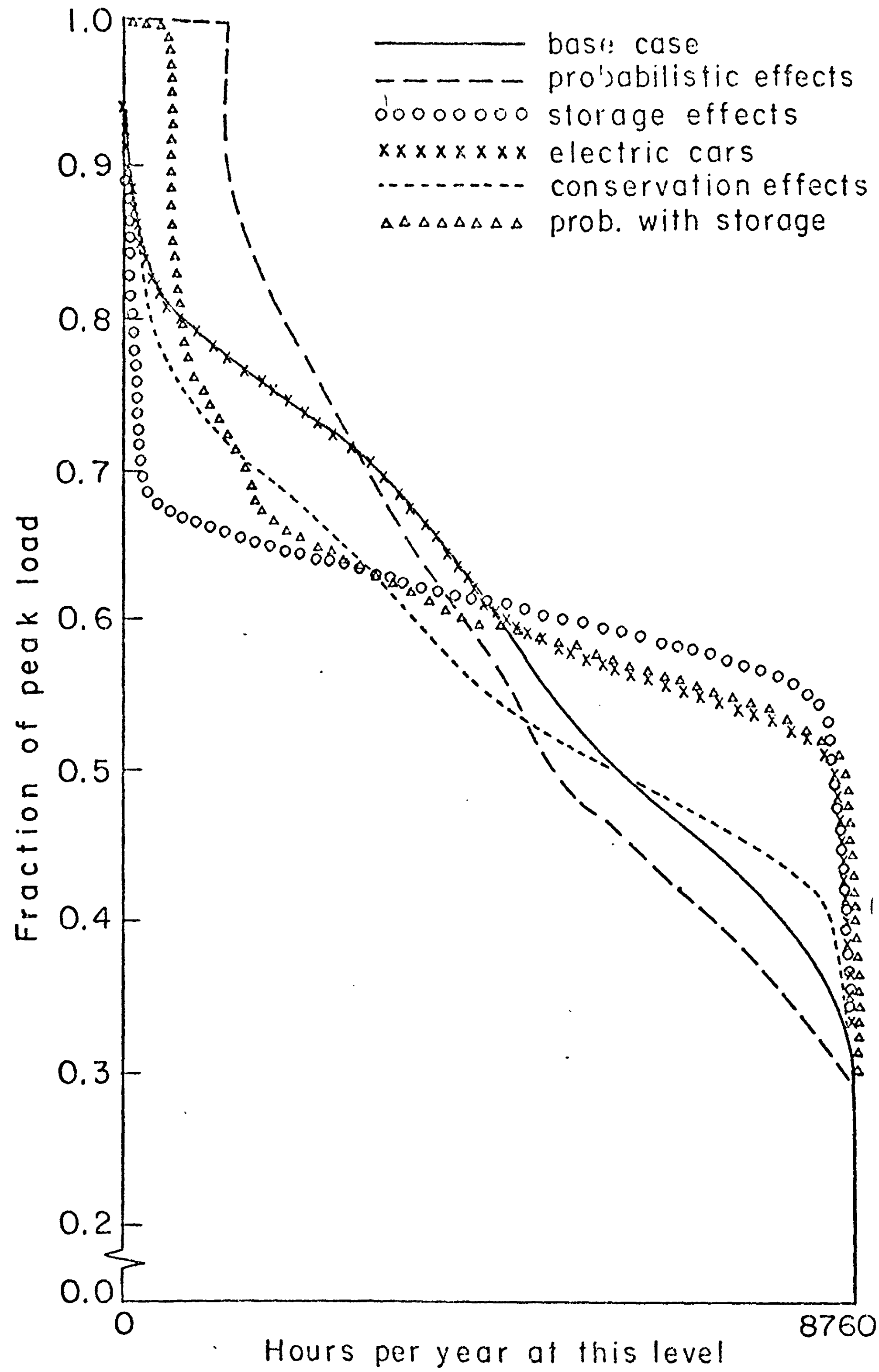


FIGURE 3.11 HYPOTHETICAL CHANGES IMPLEMENTED IN THE SHAPE OF THE LOAD DURATION CURVE

Table 3.23

Effects of Simulated Storage Devices on the Mix of Generation Types

	Installed Capacity, 1997 (GW)				
	Coal	Nuclear	Gas	Oil	Internal Combustion
Base Case	448	416	65	31	75
Simulated Storage	442	420	71	30	78

Table 3.24

Changes Caused by Variations in the Plant Retirement Age

Retirement Age	Installed Capacity, 1997 (GW) Coal	Oil	Gas	LWR	I.C.	Elect. Demand MMWH	Peak Demand GW	Cost of Elect. M/KW
40 yrs. (base case)	448	31	65	416	75	5080	967	89.5
30 yrs.	460	25	45	420	58	4957	943	92.0
25 yrs.	459	20	32	416	48	4859	924	93.7

Lead Times

The results of the experiments designed to study the effect in REM of changes in lead times are illustrated in Figure 3.12. The generation mix moves in the direction that would be expected, with nuclear capacity extremely sensitive to lead time, particularly when compared to the relative insensitivity of coal capacity. It would have been most interesting to switch roles for nuclear and coal, or to push the lead times further in some of these directions. However, internal programming inconsistencies would have resulted. In light of the potential for major delays in coal plant siting due to the potential coal-related carcinogenic effects that are being identified, it would also have been interesting to see the effects of equal lead times for coal and nuclear plants, but this would have required very substantial changes to the computer code.

Reserve Margin

Changes in the reserve margin do not produce large changes in the REM outputs (see Table 3.25). The model appropriately shows that increasing the reserve margin results in higher generating costs, which drive down the demand for electricity. Thus, the net increase in generating capacity required by a higher reserve margin is less than would otherwise be expected. For example, in the experiment with a 25 percent increase in the reserve margin, there was only a 4 percent increase in installed capacity.

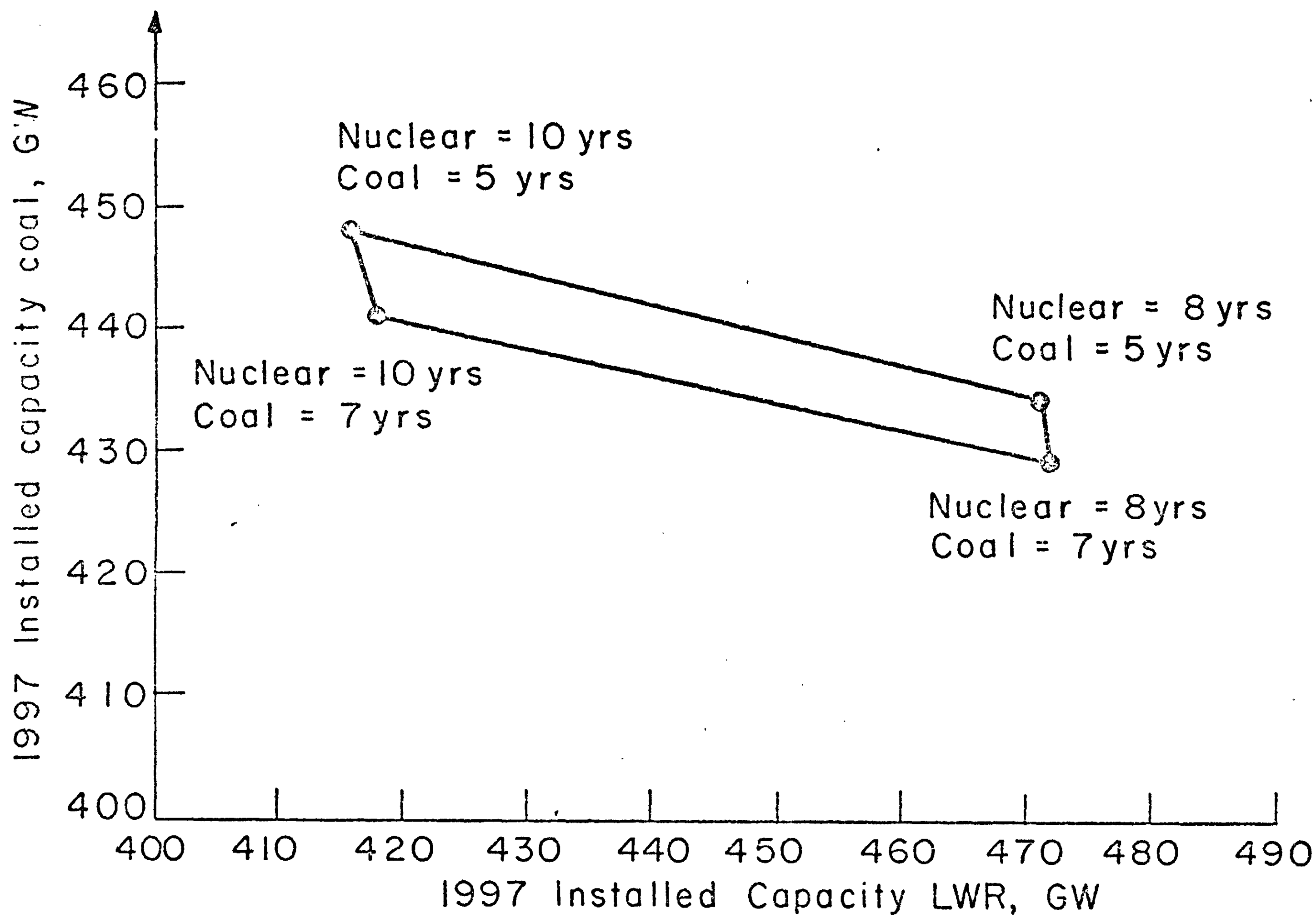


FIGURE 3.12 EFFECT OF LICENSING TIME ON GENERATION MIX

Table 3.25

Impacts of Change in Reserve Margin

	Demand for Electricity, 1990 (MMWH)	Price of Electricity, 1990 (mills/KWH)	Installed Capacity, 1990 (GW)
Base Case	3819	60.7	921
Margin up 25%	3795	61.1	954
Margin Down 25%	3862	60.2	894

<u>Fuel, Operating, and Investment Costs</u>

Figure 3.13 shows how the REM projections of electricity cost and demand respond to changes in the price of coal and in the operating costs of LWRs. Figure 3.14 then shows the combinations of coal and nuclear generation associated with the same cost changes. The direction and magnitude of the responses generally seem reasonable in relation to the initial cost changes. The pattern of response in installed capacity is similar to that in generation, though somewhat less pronounced due to the time lags involved. Other experiments showed that the effects of the cost changes follow the same general patterns even when other technologies, such as advanced coal plants or storage devices, are available in the simulation.

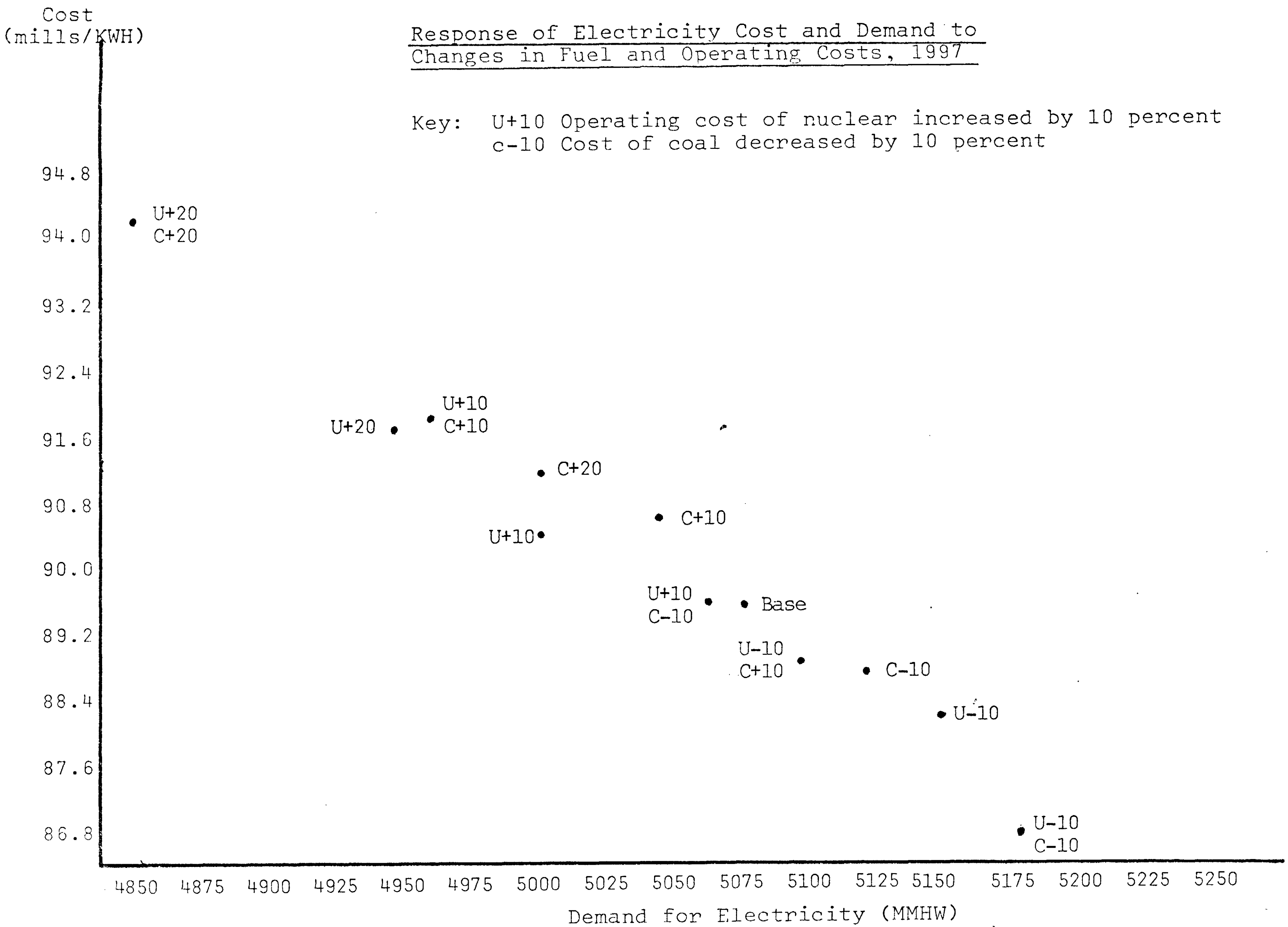
The installed capacities and generation from gas and oil fired units were virtually unaffected by changes (up to 20 percent) in the costs of gas, oil, coal, or nuclear. Apparently, in the REM structure fuel costs are not a major consideration in the purchase or operation of these facilities. Given the purposes for which these units are used, this may be a reasonable behavior pattern. Also, in the experiments with the demand submodel where much larger price changes were used, the generation from gas and oil fired units did show some modest response to fuel costs.

One final set of sensitivity experiments was run to assess REM response to changes in the investment costs for new facilities. It was expected that the response pattern would be similar to that obtained from changes in operating costs. The results of the experiments, as illustrated in Figure 3.15, confirm that this is the case. There are, of course, some differences in timing, since the changes in investment costs have to work their way through the expansion planning process.

Figure 3.13

Response of Electricity Cost and Demand to Changes in Fuel and Operating Costs, 1997

Key: U+10 Operating cost of nuclear increased by 10 percent
c-10 Cost of coal decreased by 10 percent



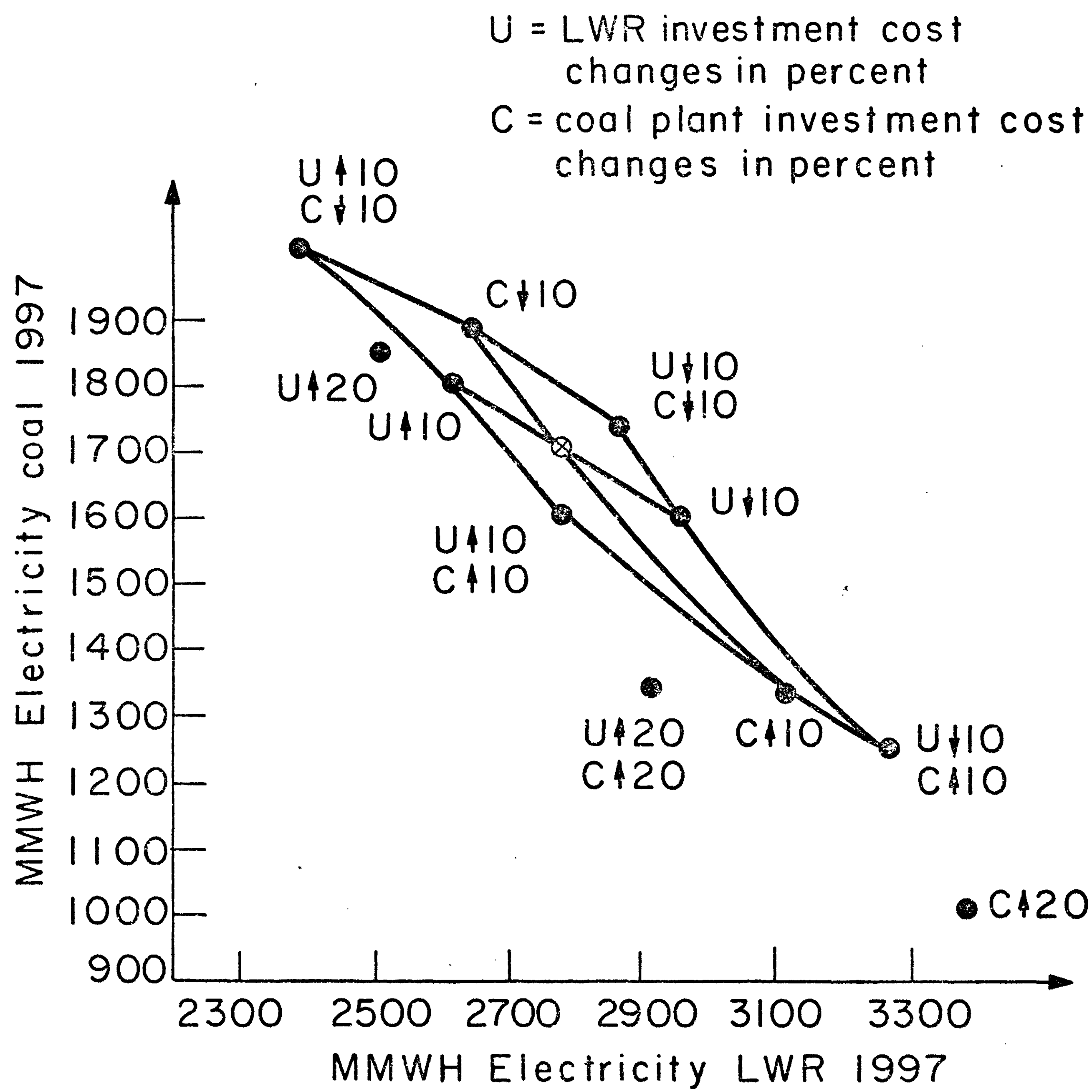


FIGURE 3.14 GENERATION MIX AND USAGE VARIATIONS WITH COAL AND URANIUM PRICE CHANGES

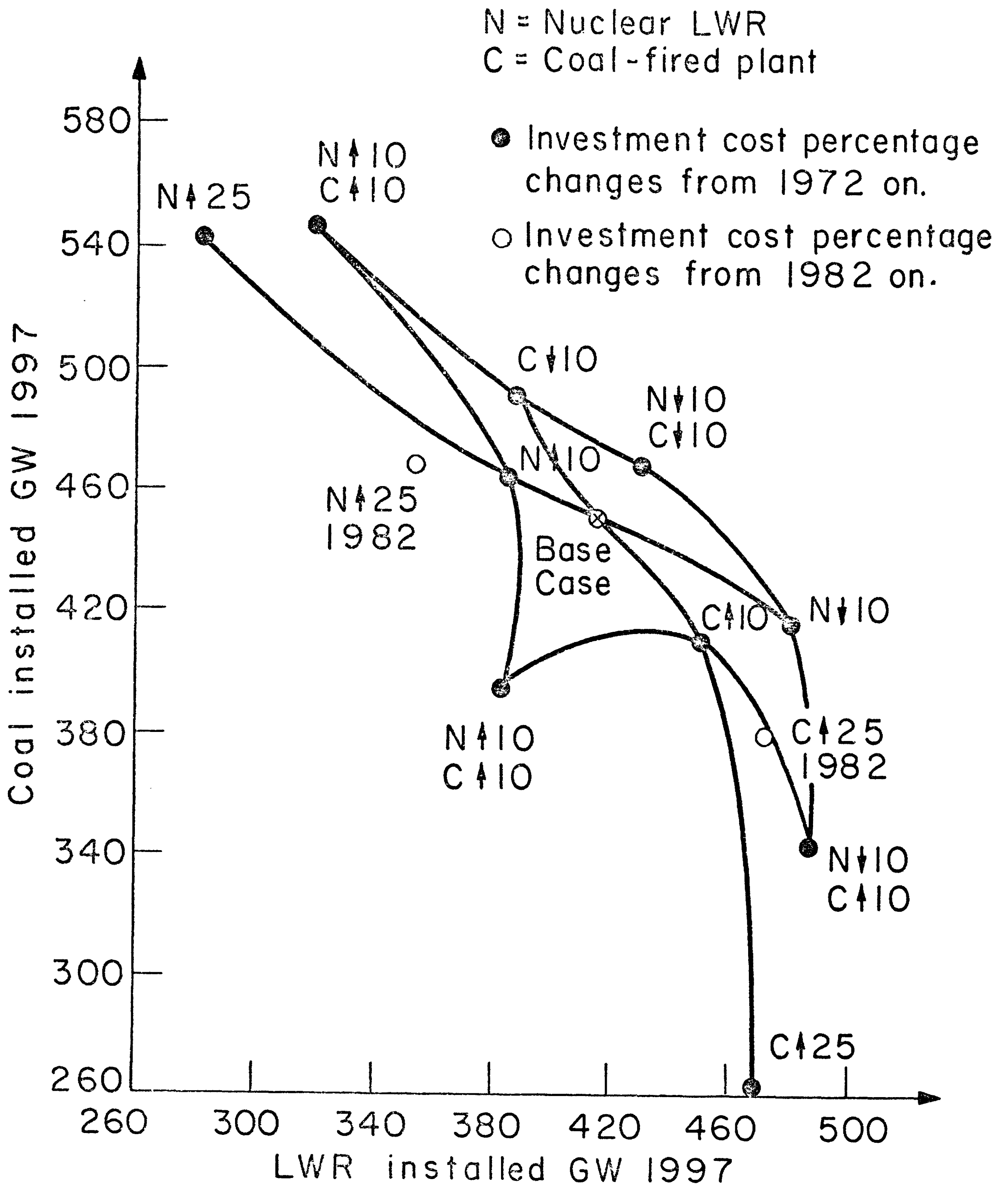


FIGURE 3.15 EFFECTS OF INVESTMENT COST CHANGES ON THE MIX OF NUCLEAR AND COAL INSTALLED CAPACITIES

3.5 Financial/Regulatory Submodel

3.5.1 Outline of the financial/regulatory submodel

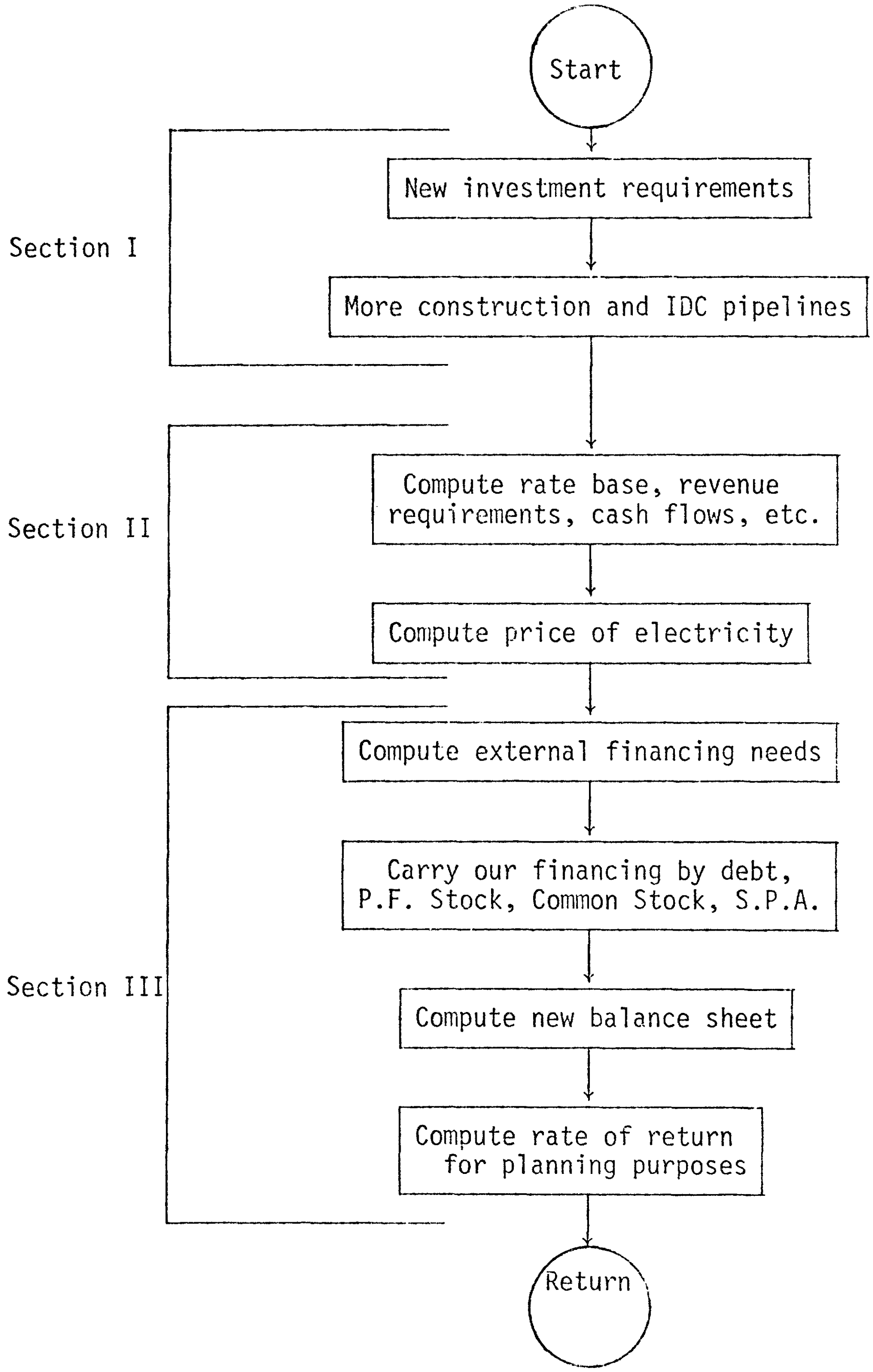
One of the most innovative features of REM is that it includes an explicit model of both the financing practices and regulatory environment of utilities, providing a complete linkage between the supply and demand submodels. In REM, the financial/regulatory and model has pivotal importance in the overall model behavior and applications. As was discussed in Chapter 2 (see Figure 2.1), it provides two essential inputs to other models: the price of electricity to the demand submodel, and the capital charge rate used in the supply submodel.

The financial/regulatory model can be divided into three general sections, as illustrated in Figure 3.16. The first section maintains the equipment inventory and calculates the total finance required on new construction each year. Files are maintained on each of the nine plant types by region, and each year the completed construction is added and the old plant is retired. The requirements for interest during work in construction, and the total value of work in construction, are calculated.

The second section is principally a simulation of the regulatory procedure which calculates the rate base and the allowed rate of return. State regulatory commission rules are used to do this. Gross revenue requirements and the average price of electricity are computed. The revenue and total energy production figures apply to a given year, and the price is that to be charged in the succeeding year (a regulatory lag of one year). Finally, some accounting and cash flow figures are

Figure 3.16

Flow Diagram of Financial/Regulatory Submodel



calculated, such as depreciation (using straightline and accelerated methods), taxes (both property and income), and retained earnings and dividends.

The third section of the submodel estimates new financing needs. Normal financing conventions are followed here; the model does not have a representation of the capital market but instead uses fixed interest rates and limit ratios. Capital is obtained from a hierarchy of sources, with any residual financial requirements met by a State Power Authority (SPA), a hypothetical lender of last resort. The amount of SPA finance has been used in the model applications as a measure of capital shortage.

The model updates the equipment history files every six months. At the end of each year, the gross revenue requirement for the next year is obtained using current production cost figures, taxes, depreciation, assets, and so on, as they stand at the end of the year. The revenue is divided by the actual energy production for the past year in order to obtain the price of electricity to be charged for the following year, implying a one-year regulatory lag.

A detailed outline of the steps in the model and some of the most important model equations are presented in [34]. For the derivations the reader should refer to Kamat [35].

3.5.2 Overview evaluation

An important simplification made in the financial/regulatory submodel is that instead of using supply curves for the various sources of funds, fixed "rule-of-thumb" constraints are placed on the amounts of funds that can be raised from each source. For example, the existing submodel shows debt being available at constant cost up to a debt/asset ratio of 60 percent. No borrowing is allowed beyond that point at any cost. This situation is illustrated in Figure 3.17a. In practice, utilities may be somewhat able to push up their debt/asset ratios, though by doing so, their bond rating may drop and the interest rates they would have to pay would go up. This situation is illustrated in Figure 3.17b. Similar supply curves could also be used for the other sources of funds. This would increase the flexibility of the model, since as Kamat points out:

> One drawback . . . which though not serious could be improved upon . . . is the absence of a capital market. The simplistic constraints used as a stop gap measure serve their purposes well, but cannot be relied upon to be very accurate. The rationale for using the constraints may not be supported by future electric utility practices [35].

One of the principal parameters calculated in the financial/regulatory submodel is the price of electricity, but it is an average price and does not imply any tariff structure. Thus, the effects of changes in tariff structure cannot be explicitly investigated with REM. In particular, the effect of eliminating declining block rates or the introduction of peak load pricing cannot be directly analyzed. Instead, the effects of these policies on the shape and level of load duration curves must be estimated by the user and then supplied as input information to REM. Of course, even if the financial/regulatory submodel did estimate the tariff structure, this information could not be used by REM without improving the structure of the demand submodel.

There is also some question about the appropriateness of the regulatory lags in the model. The first point is that the length of the

Figure 3-17a

Formulation of Supply of Funds Used in Current REM

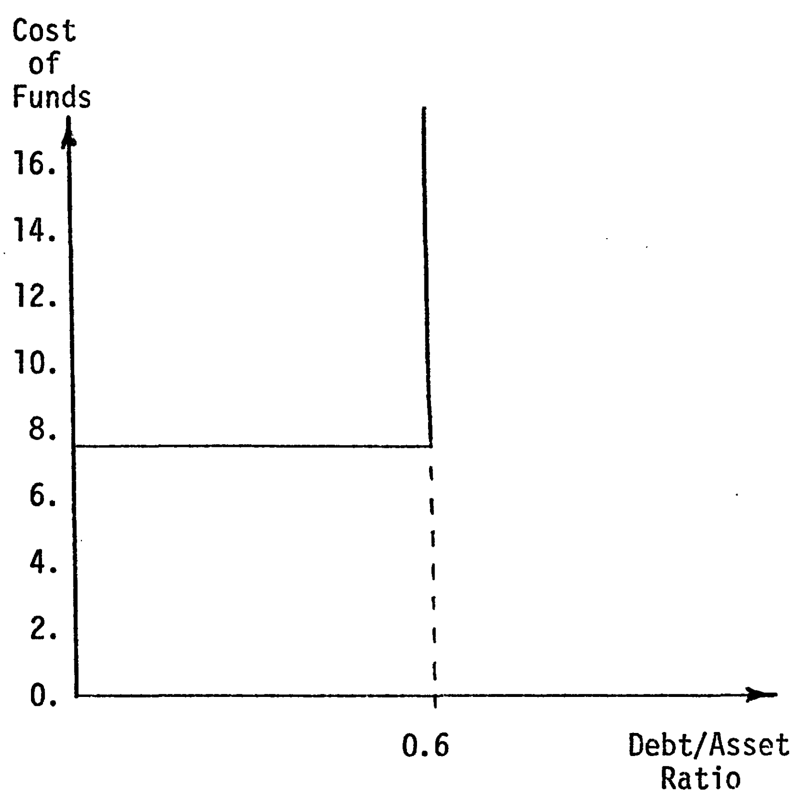
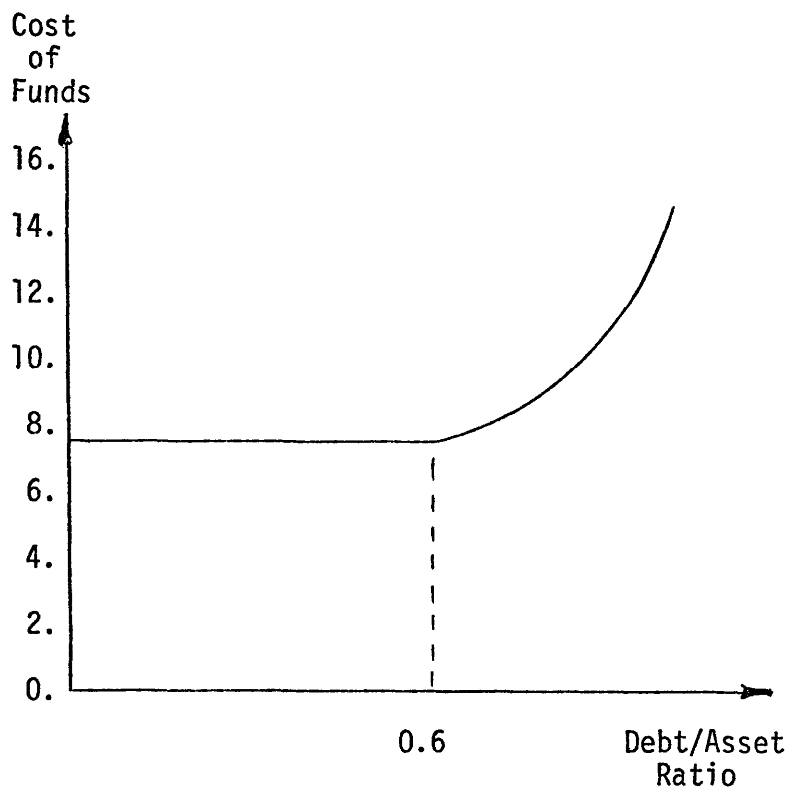


Figure 3-17b

Alternative Formulation of Supply of Funds Showing the Cost of Funds Increasing With Debt/Asset Ratio



lag cannot be easily varied; it is fixed in the model structure, and does not reflect the administrative delay involved in regulation, but rather is an artifact of the model. Second, along with the exclusion of the regulatory lag, an important non-lagged factor is omitted from the model--namely, the fuel adjustment clause. This clause enables utilities to pass on escalating fuel costs without a regulatory hearing and typically with a delay of no more than 30 to 90 days. Utilities regard the fuel adjustment clause as vital to maintaining satisfactory cash flows and, to some extent, the clause was introduced to compensate for the regulatory lag in rate base hearings. It may be that by omitting both the administrative regulatory lag and the fuel adjustment clause, the results from REM come out just about right; that is, the effects of the two omitted factors may just about cancel out.

Another point that can be made concerning the general operation of the financial model is that in all cases the interest rates in the model are fixed over time. Thus, over time the marginal rate will come to equal the average rate, and the provision for "rolling-in" new interest rates has no effect. It is an easy task, however, both conceptually and from a programming point of view, to modify the structure so a trajectory of rates can be put in. This would be desirable because interest rates have pivotal importance in the model, yet are subject to considerable fluctuation and uncertainty over time.

Care must be exercised in changing the construction lead time of nuclear plants. The nuclear cash flow vector is dimensioned to be ten years long, and if longer than ten years is specified, cash flows will be obtained from other arrays, which will give incorrect results. If a lead time shorter than 7.5 years is specified, the plant will not be allocated 100 percent of its construction costs. This is because the first 1.5 years of construction of a nuclear plant have zero cash flow in the present model. New cash flow schedules need to be substituted if the time is to drop below 7.5 years. This would imply there is a slight error in the case analyzed by Baughman-Joskow [33] where the nuclear lead time is cut to 7 years.

In general, the structure and implementation of the financial/regulatory submodel seems to produce a reasonable representation of the utility industry practices. The conclusions reached from discussions with utility representatives were that the complexity and depth of the model is appropriate for regional analysis. The organization of the model into the three sections shown in Figure 3.16 is also appropriate and is similar to the way utilities do their own accounts and modeling. The linkage between the financial/regulatory submodel and the supply and demand submodels replicate the flows of information found in the real situation. The model structure could be improved with some of the modifications discussed above but, with the exception of the concept of the State Power Authority, discussed below, the REM financial/regulatory submodel seems to be quite well structured.

Perhaps the single most troublesome feature of the financial/regulatory submodel is the way in which it handles a situation where the simulated utilities encounter a "capital shortage". Without question, one of the major issues for the electric power industry is the potential difficulties involved in obtaining the financing required to support needed capital investments. It is clear that the utilities themselves are greatly concerned about this question, and from the published materials, it is apparent that analysis of a potential capital shortage was intended to be one of the principal policy applications of REM. While REM is not sufficiently disaggregated to deal with the financial situation of an individual utility, the model is set up to deal with the financing process on a national and regional basis. If the purpose of the REM financial model is to evaluate the impacts of possible capital shortages, how well is the model structured to handle this? There is reason to suspect that the model as it is presently structured can give misleading and possibly erroneous results.

The principal source of difficulty is that a hypothetical source of finance called the State Power Authority (SPA) is used to fill any capital shortage. It is, in effect, a residual which closes the model after all other sources of finance are exhausted. Since it is unlikely that the government would ever lend money in the suggested amounts with no strings attached, the introduction of the SPA seems to lend credibility to an option which is very unlikely to exist in real life. Instead of giving a name to a non-existent source of low cost funds, it would have been a happier, and less confusing, choice of words to call the potential capital shortage what it is -- a potential capital shortage. The authors do, in fact, explicitly recognize that SPA finance is actually a capital shortage. The problem is that the version of REM used in all applications to date has also treated SPA finance as if it were a real source of funds.

Apart from the semantics, there is a question as to the effect of this imaginary source of finance on the simulated investment decisions. There are two principal variables where the cost of capital appears: the capital charge rate and the regulated rate of return on the rate base. The capital charge rate is calculated as:

$$CHRATE = 1/L + \frac{D * DINTN + \dfrac{(TE * R_e + PS * PINTN)}{1 - TAXINC}}{D + TE + PS}$$

where:

D	=	total debt capital,
DINTN	=	interest rate of new debt capital,
TE	=	total equity capital,
R_e	=	regulated return on equity,
P_s	=	total preferred stock capital,
PINTN	=	interest rate on new preferred stock,
TAXINC	=	effective tax rate.

It can be seen that the amount of SPA finance and the interest on it do not appear at all in this formula. Thus, the capital charge rate as calculated is quite independent of SPA finance and will remain unchanged so long as interest rates on other sources of funds and the mix of those sources do not change very much. This means that the average levelized cost for generation alternatives used in the generation expansion model, which depends on the charge rate, is insensitive to the amount or cost of SPA finance.

On the other hand, the relationship used to calculate the regulated rate of return on the rate base does include SPA finance:

$$RATE = \frac{D * I_D + PS * TE * R_e + SPA * I_{SPA}}{D + PS + TE + SPA}$$

where:

I_D = average interest rate on debt,

R_p = preferred stock dividend rate,

R_e = regulated rate of return on equity,

SPA = State Power Authority financial capital,

I_{SPA} = interest rate on SPA finance.

The regulated rate of return is essentially a weighted average of the cost of capital. It is based on average historical costs, rather than on the incremental costs which are used in the capital charge rate formula. In the published results from REM, the interest rates used in this equation are 9 percent for debt, 5 percent for preferred stock, 14 percent for equity, and 6.6 percent (60 percent of the new debt interest rate) for SPA finance. Since the SPA provides the lowest cost source of funds, this means that the regulated return on the rate base will fall as more SPA finance is used. Thus, as the capital shortage facing electric utilities becomes greater, the regulated return on the rate base becomes lower. This, in turn, lowers revenue requirements, and thus lowers the price of electricity. This stimulates demand, which increases the need for capital investments, and thus makes the capital shortage even more intense.

There is a further difficulty in that the capital charge rate and the regulated return on the rate base do not move together. As SPA financing increases, the regulated return falls while, as noted above, the capital charge rate remains essentially unchanged. This implicitly assumes that the regulatory commissions, in setting the price for electicity, take the cost of SPA financing into account, while the utilities in making their expansion plans do not consider the cost of SPA finance. Thus, as it stands, the REM financial model is logically inconsistent. SPA interests costs should either be included in both the regulated return on the rate base and the capital charge rate or in neither. In addition, the cost of SPA finance is now included in the calculation of the capital charge rate.

If a higher rate were to be charged for SPA finance, this would remove the phenomenon of a declining marginal cost of capital. However, even if there were a large penalty rate on SPA finance, the capital charge rate (since it does not include SPA finance) would not be affected, and thus would continue to drive the average levelized cost forumula as though no shortage existed. As a result, the industry expansion plans would not be altered in response to the capital shortage. In particular, utilities would have no incentive to begin building generating plants which, although they might have higher running costs, would have lower capital costs.*

These limitations in the financial model also have implications for REM's applicability in other areas. For example, in simulating the process by which utilities choose among alternative types of generating plants, the REM results may understate the advantages of capital saving

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*In response to these criticisms of the SPA interest costs (which were communicated to the authors), the most recent versions of REM use an SPA interest rate which is equal to the cost of equity, instead of holding it at 60 percent of the cost of new debt, as in the previous results. This means that the SPA interest rate has been increased from 6.6 percent to 14 percent.

technologies. Since the capital charge rate does not respond to reductions in the capital shortage, the model will tend to underestimate the benefits of technologies with lower capital requirements. Conversely, the model will underestimate the cost of capital-intensive technologies. This can lead to inaccurate estimates of the effects of policies well outside the financial area. A reduction in the cost of nuclear fuels, for example, would be expected to increase the attractiveness of nuclear generating plants. Since nuclear plants are relatively capital intensive, this would be partially offset by the effects of having to raise larger amounts of capital. In the model, however, the increase in capital costs would not enter into the generation expansion plans. As a result, the model would tend to overestimate the effects of the reduction in nuclear fuel costs. If REM is to be used for policy analysis, it is essential that the structure of the financial/regulatory submodel be improved to deal more adequately with financing requirements.

3.5.3 Design of the Simulation Experiments

The principal characteristic of the financial model with which the overview assessment took issue was the non-inclusion of SPA finance in the capital charge rate, and the lack of a capital market to close the capital "shortage." Apart from this, the financial model appeared innovative, particularly by being set in the context of a large electricity simulation model, and well structured. The in-depth experiments are concentrated, therefore, on these points. Sensitivity studies were also performed on all interest and dividend rates, since these are pivotal parameters in the financial model.

Costs of Alternative Financing Methods: The first set of experiments considered the effects of three alternative ways of meeting the full financing requirements projected by REM. All methods specified that funds had to be raised to eliminate the capital shortage and the cost of the additional funds was to be included in the capital charge rate. As in the original REM runs, the projected amount of SPA finance was treated as an estimate of the size of the capital shortage. The following three alternative methods were used to close this gap:

- Debt financing: The additional funds are raised by issuing bonds, with the interest rate on the new bonds increasing, according to a specified debt schedule, as the debt/asset ratio becomes higher.
- Fixed ratio debt/equity financing: The additional funds are raised by issuing debt and equity in fixed proportions, so the utilities debt/equity ratio is held constant, though the debt/asset ratio will rise.
- Equity financing: The capital shortage is closed by issuing equity, perhaps by selling stock at less than par, so the equity/asset ratio rises while the debt/asset ratio remains constant.

The purpose of these experiments is not to build an empirically accurate model of the capital markets, but to see how the REM outputs might be affected if such a model were built.

Interest Rate Sensitivity: The principal equations in the financial/regulatory submodel were examined analytically to identify the most critical parameters. The analytical results indicated that interest rates, particularly the rate on debt, exert the greatest leverage on the capital charge rate, the regulated return on capital, and the required revenue. The following experiments were run to quantify the impacts of changes in these key variables:

- Debt interest rate increased by 20 percent,
- Preferred stock interest rate increased by 20 percent,
- Equity dividend rate increased by 20 percent, and
- SPA cost increased by 20 percent.

3.5.4 In-depth assessment

Costs of alternative financing methods: The debt schedule used in the first experiment specifies that, when the debt/asset ratio is pushed above 0.6, the interest rate on debt increases by 50 basis points for each increase of one percentage point in the debt/asset ratio. For debt/asset ratios up to 0.6, the interest rate is simply held at the rate specified in the basic REM data (8.5 percent). This is not intended to be a model of how the real world would actually operate, since the interest coverage requirement constraint would prevent such a large proportion of debt from being raised. The second experiment uses a 60/40 mix of debt and equity with the interest rates set at 10.5 and 16.0 percent, respectively. To reflect the fact that a higher rate may have to be paid to obtain additional financing, these rates are set two percentage points above the corresponding interest rates in the REM data. The third experiment assumes that the financing gap can be closed by issuing more equity at a cost of 14 percent, the rate used in the REM data.

As shown by the results in Table 3.26, none of the experiments had a significant impact on the REM projections of the mix or level of installed generation capacity. Although there were some large increases in the capital charge rates, the structure of REM is such that these were not translated into changes in installed capacity, at least not by 1997.

On balance, it appears that while inclusion of SPA finances in the capital charge rate is important from the point of view of consistency and "correctness", it does not have pivotal importance for model behavior, as might be inferred from the overview assessment. In fact, as will be shown later, increasing either the debt interest rate or the equity dividend rate by 20 percent has a greater effect on system growth. This, then, is an instance in which the results from the in-depth assessment indicate that a structural problem identified in the overview assessment has impacts that are quantitatively insignificant. However, another possible explanation of the experimental results is that the REM response to drastic changes in the capital charge rate is an underestimation of what would happen in practice.

The Model Assessment Group has learned that, as a result of the overview assessment of the financial model that was circulated to the model authors, the financial model has been modified along the lines of the third financing alternative. SPA finance, though still the residual source of funds is now included as <u>equity</u> in the capital charge rate, with the interpretation as given above. We feel this illustrates a

Table 3.26

Impacts of Alternative Financing Methods, 1997

	Capital Charge Rate, South Atlantic Region (percent)	U.S. Installed Capacity (GW)		
		Nuclear	Coal	Total
Base Case	13.2	416	448	1147
Alternative Financing Experiments				
Debt Financing	19.1	406	447	1132
Debt/Equity Financing	14.0	414	449	1147
Equity Financing	15.2	407	453	1143

valuable aspect of the assessment process. The model authors and assessors have now reached to a common point of view on this important aspect of the model and, in the process, the usefulnness of the financial/regulatory model has been enhanced.

Interest Rate Sensitivity: The effects of increasing the various interest rates by 20 percent are shown in Table 3.27. Increasing interest rates pushes up the cost of electricity and thus reduces the demand for electricity. This reduces the total need for generation capacity, but changing the interest rates has little impact on generation mix. Higher interest rates typically reduce the capital shortage, though an increase in the rate on debt had the opposite effect. This is because, with the higher rate, the requirement in REM of a 1.75 interest coverage ratio becomes the operative constraint and the debt/asset ratio is forced down.

The results indicate that increasing the equity dividend rate drastically reduces the capital shortage projected by REM. There are several reasons for this. First, the marginal cost of capital is increased. This is directly reflected in the regulated return on the rate of base, the price of electricity, and hence the demand. But the most important reason is that, with a higher equity dividend, the rules of thumb used in REM will allow the utilities to issue more equity, thus reducing the need for SPA finance.

The process used is that a predicted total equity dividend is found from smoothing previous values (using the forecasting routine). The

Table 3.27

Interest Rate Sensitivity, 1997 Results

	Price of Electricity (mills/KwH)	Demand for Electricity (MMWH)	Capital Shortage (SPA finance) ($ billions)	Installed Capacity (GW)		
				Nuclear	Coal	Total
Base Case	89.5	5080	180	416	448	1147
Interest Rates Increased by 20 Percent						
Debt	92.0	4920	205	397	438	1110
Preferred Stock	89.5	5051	171	414	445	1141
Equity	92.2	4874	33	396	437	1110
SPA Finance	90.4	5047	159	413	443	1138

predicted dividend is multipled by a "markup" ratio, which is set at 1.1, and then divided by a target value of earnings to book value of equity. The latter parameter is fixed as 0.12 before 1974 and 0.14 after 1974. The user should be alert to the fact that these parameter values are "hardwired" into the financial model. Also, this parameter in the model is independent of the regulated return on equity, even though one should reflect the other. Although this simple procedure is not entirely satisfactory, it is difficult to see how it could be improved without considerably complicating to the financial model.

3.6 Summary and Recommendations

The ultimate objective of the model assessment process is to draw conclusions concerning the model's applicability to the analysis of policy issues. The outcome of the assessment will depend critically on the range of issues over which the model's applicability is evaluated. To help structure our assessment of the Baughman-Joskow Regionalized Electricity Model, we have compiled a list of potential policy applications (Table 3.28). The list includes all the issues to which the model has already been applied, as well as those policy issues for which, in our opinion, future applications of the model might be considered. There is no implication that the model builders themselves would suggest that REM is appropriate for all of these applications. We have tried to make the list wide-ranging in order to make our comments useful for potential users who are not familiar with the model's properties.

3.6.1 Policy observations: General applicability

As with any model, REM has made simplifications or abstractions from the complexities of real-world operations in order to construct an intelligible, workable model. Some of these abstractions have serious and pervasive implications for the general applicability of the model. These major, general issues will be discussed prior to considering the specific applications in Table 3.28.

The modeling of the process by which capacity-expansion and generation-mix decisions are made in the electric utility industry is crucial to most, if not all, of the potential applications of REM. The

Table 3.28

Potential Policy Applications to be Considered in Assessing the Baughman-Joskow Regionalized Electricity Model

1. Changes in factors affecting electricity demand growth paths
   - economic/demographic trends
   - conservation policies

2. Load management
   - peak load pricing*
   - cogeneration
   - seasonal pricing

3. Impacts of changes in cost factors
   - capital costs for new plants
   - fuel prices*
   - wage rates
   - taxes (possibly a Btu tax)

4. Changes in resource supply conditions
   - resource constraints*
   - increasing cost supply schedules

5. Costs of financing*

6. Industry responses to capital "shortage"
   - state financing*
   - less capital-intensive technologies
   - reduce growth
   - reduction in plant reserve margin

7. Regulatory policies
   - regulated rate of return*
   - inclusion of work in progress in rate base*
   - exclusion of noneconomic plants from rate base*
   - regulatory lag

8. Alternative lead times for capacity expansion*

*Applications for which examples already exist in the REM documentation.

Table 3.28 (continued)

9. <u>Environmental constraints</u>

   - siting restrictions
   - capital equipment requirements*
   - increased operating costs*

10. <u>Technology assessment</u>

   - advanced generation technologies: centralized and distributed
conventional and
nonconventional
cogeneration
fuel conversion
   - nuclear: non-LWR, breeder, etc.
   - storage
   - T and D

optimization logic used in the generation expansion model of REM imparts an all-or-nothing character to this decision process. The lack of risk aversion, resource limitations, and similar real-world constraints cause the model to put all investment into the single plant type, which has a cost advantage over the other types, even when the advantage is very slight. This potentially serious oversimplification may, to some extent, be dealt with by the regionalization in the model. That is, the all-or-nothing decisions in each region may, when aggregated over the country as a whole, produce national projections that are more plausible than the projections for the individual regions. REM is, for this reason, most appropriately viewed as a national model that uses regionalization as a device for improving the quality of the national simulations.

REM assumes that optimum system configuration is determined at each point in time, independent of previous or future decisions. Since the optimum generation mix in REM does not directly incorporate information concerning the configuration of the existing system, it does not allow for correction of overbuilt plant types. This exaggerates the use of baseloaded facilities, which in the REM base case are dominated by nuclear units. Also, the nuclear plants modeled in the planning process seem to receive too much credit for cycling capabilities, further reducing the use of peaking and cycling units.

REM does not incorporate feedback between the planning of system expansion and the simulation of system operation. In particular, the capacity factors used in planning are not checked for consistency with the capacity factors likely to be acheived in practice. This is an important point, because the simulation experiments show that the values specified for the availability (or capacity) factors have critical impact on the results produced by the model. Relatively small variations in availability cause significant changes in outputs, such as the mix of various types of installed generation capacity. This is a reasonable response pattern, but clearly, accurate determination of maximum capacity factors is a vital issue and much care must be taken in forecasting these into the future. However, the model's performance using current values for capacity factors and conventional load duration curve representation gives cause for concern with regard both to the base case results and policy applications. The base case availability factors in some case exceeded the current practice values by 15 to 20 percentage points. Furthermore, variations in the specified maximum capacity factors within seemingly reasonable limits produced results well outside the range of believability.

The simulation experiments also showed that the electricity generation component of REM performs in a more unpredictable and unsatisfactory way than would have been supposed from the overview assessment. It was particularly disturbing to find an undocumented portion of the model that arbitrarily raises the usage factors for LWRs above the specified limits whenever the available generation capacity in a region falls below the level of demand. In several of the simulation experiments, the usage factors for LWRs reached levels in some regions that were clearly unrealistic (up to 0.99). There is no way for a user of REM to know when the specified limit on the LWR capacity factor will be overridden by the program logic. Nor is there any way for the user to keep LWR capacity factors in line with those for other types of generating plants. It is essential that some better method be developed for handling electricity supply deficits in REM.

A final general point concerns the method by which REM forecasts future values for variables such as electricity demands, capital costs, and operating costs. The simulation experiments showed that the forecasting subroutine in REM has a crucial influence on the outputs produced by the model. The forecasts are made using a linear extrapolation procedure. If the variables are, in fact, growing exponentially, the linear extrapolation will result in a persistent underprediction. An experiment was conducted in which an exponential forecaster was substituted for the linear forecaster and the result was a substantial increase in the use of nuclear facilities relative to coal plants. Further it was disconcerting to find that different ALPHA values were wired into the code, overriding the value provided by the user.

Another set of experiments showed that the results of REM as a whole were also extremely sensitive to changes in ALPHA, the weighting parameter used in the forecasting subroutine. When the forecasting subroutine is used to simulate the process by which utilities formulate their own projections of future values, there is no way that ALPHA can be measured or even directly estimated. Since the REM results are extremely sensitive to changes in ALPHA, the only way of dealing with this in policy applications is to carry out the analysis using several alternative values for ALPHA. Users of REM should be alerted to the need for this type of sensitivity analysis.

3.6.2 Applicability in specific areas

The simulation experiments indicated that, within its limited design objectives, the demand submodel functioned reasonably well. The principal objective of the demand submodel is to show how changes in electricity prices, that come as outputs from the financial/regulatory submodel, affect the demands for electricity, that are provided as inputs to the supply submodel. The lack of detail in the demand model implies that REM should not be used to study policies that affect the electricity rate structure or to study policies that affect the demand structure itself. If these restrictions on the range of applicability are accepted, the demand projections and response patterns in REM seem fairly reasonable.

Looking at the first items in Table 3.28, it appears that REM can be used to simulate the effects of changes in the exogenous factors affecting the rate of growth in the demand for electricity. The accuracy of the results is, of course, dependent upon the empirical validity of the demand submodel itself. Since there are improved demand models now available, it may be desirable to substitute one of them for the existing demand submodel. Also, a potential user of REM should be aware that the REM results are quite sensitive to changes in the parameters in the demand submodel. Introduction of parameters estimated from data covering different historical time periods causes substantial differences in the model outputs.

REM has only limited capability for analyzing such areas as energy conservation policies. However, if the policies can be appropriately represented as increases in effective fuel prices, the model can handle this quite well. The simulation experiments showed that a Btu tax can, for example, be introduced in a fairly straightforward fashion. Other policies, such as end-use efficiency standards, cannot be introduced directly into REM. The initial impacts of such types of policy would have to be analyzed outside REM and then fed into the demand submodel as an exogenous change.

Load management policies, such as time-of-day or seasonal pricing, are essentially designed to change the shape of the load duration curve. Since the shape of the load duration curve in REM is exogenously specified, these policies cannot be introduced directly into the model. Instead, some side calculations have to be performed to translate the policy actions into changes in the load duration curve. Unfortunately, this means that a major part of the policy analysis is buried in the side calculation.

Another problem arises from the fact that the shape of the load duration curve is independent of changes in demand. Thus, if peak load pricing, for example, causes significant changes in the composition of demand, this will not result in any changes in the shape of the load duration curve. This limitation is reinforced by the fact that the demand model uses a single price for electricity. As presently structured, it is unable to deal with time-of-day or declining block rate pricing structures.

In general, by using a load duration curve that is exogenously specified and only measured annually, REM is not very well structured to deal with load management policies. Furthermore, even if the shape of the load duration curve is changed, this has relatively limited impact on generation expansion planning,since baseload plants (primarily LWRs) tend to load follow in REM. This causes the model to underestimate the impact on the need for peaking and cycling plants. Some of the simulation experiments made drastic changes in the shape of the load duration curve, and this had almost no effect on REM's projections of installed capacity and generation mix.

The model's response to changes in factor costs (the third item in Table 3.28) seemed generally reasonable. There is one important point, that should be noted concerning the way factor costs enter the generation expansion model. The relevant costs are the predicted costs for future time periods; these are endogenously determined in the REM forecasting routine by extrapolating past values. This means that REM cannot be used directly to investigate the effects of changes in expectations. For example, REM will show capacity commitments in the current time period as being the same whether utilities expect factor costs to increase at 5 percent a year or 10 percent a year in the future. Factor costs used in the generation expansion model are completely determined by past events; they do not respond to expectations for the future. This is contrary to the information given in the REM documentation.

REM's ability to deal with changes in resource supply conditions (item 4) is limited to those situations in which the change can be exogenously specified as a change in the resource price. In the present model structure, supply prices do not respond to changes in demand levels. It is assumed in REM that changes in the electric utility industry's demand for coal, for example, do not affect the price of coal. In the simulation experiments utilizing the market clearing FEA price solutions for its reference cases based on $13.00 and $16.00 oil, the results were very close to the REM base case results, but the generation mix differed substantially.

The model responded in a generally appropriate fashion to significant changes in the prices for natural gas and oil. It is not possible to enter constraints on the availability of fuel supplies directly into REM, and experiments that attempted to proxy these constraints by treating them as if they were equivalent to very large increases in fuel prices did not produce very satisfactory results. The results were distorted by the fact that the hypothetical price changes affected the total demand for energy and also the relative shares of the different types of fuels. It does not seem appropriate to apply REM to the analysis of policies (such as import quotas) that place absolute limits on the availability of resources.

The next three policy areas in the table (financing costs, responses to a capital shortage, and regulatory policies) are highly interrelated and will be discussed together. One of the most innovative features of REM is that it includes an explicit representation of the financial and regulatory processes involved in the operation of the electric utility industry. The results of the simulation experiments indicate that the financial submodel is robust as well as plausible. Sensitivity analysis of the major interest rates indicated response patterns that were both qualitatively and quantitatively reasonable. One shortcoming in the structure of the financial/regulatory model is that an infinite amount of SPA finance (which is really a measure of the capital shortage) is available at a relatively low interest rate. More importantly, the cost of SPA finance is not included at all in calculating the capital charge rate. Therefore, no matter how much SPA finance is used, and even if a penalty rate is charged, the capital charge rate will not rise. This means that increases in the cost of financing resulting from the increase in capital requirements will not be transmitted to the generation expansion model, and will provide no incentive for less capital-intensive investments.

This structural weakness was identified in the overview assessment, and it was thought that it would have a major impact on the REM results. Several experiments were carried out in which the assumptions concerning the cost of SPA finance were altered significantly and the costs were included in the capital charge rate. The results of these experiments, as expected, showed an increase in the capital charge rate, causing the system to move toward less capital-intensive expansion plants. Somewhat surprisingly, however, the simulation experiments showed that the magnitude of this shift was moderate. Thus, a structural weakness in REM that seemed quite important in the overview assessment was shown through in-depth experiments to have relatively limited quantitative significance.

The detailed specification of the regulatory model gives REM the capability of dealing with a variety of regulatory changes. The regulated rate of return is an explicit policy variable in REM, and changes can be introduced in a straightforward fashion. The sensitivity experiments showed that changes in the regulated return on equity have a very significant impact on model results, particularly with regard to the potential capital shortage confronting the industry. The possibility of including work-in-progress in the rate base is another policy issue that REM was designed to handle.

On the other hand, some types of regulatory policies can be investigated only with considerably greater difficulty. For example, there seems to be no direct way of introducing a policy to exclude noneconomic plants from the calculated rate base. In fact, the prespecified plant lifetime is set at the same length (40 years) for all types of plants, whether nuclear reactors or gas turbines. The model as it now stands is also not designed to deal with lags in the regulatory process. Cost increases in one year are passed on in price increases at the start of the following year. Modifying the structure of the model to introduce regulatory lags is conceptually quite easy, though it would require some reprogramming.

The impact of changing the lead times for new generation capacity (item 8) is critically dependent on the validity of the forecasting routines in REM. Both the load prediction and the cost forecasting routines use linear extrapolation techniques. If the actual growth is exponential, this will persistently underestimate the true growth rates, and the longer the lead times, the more serious the error that will be introduced. It is not clear that the load prediction techniques used by utilities are as naive as the model represents them, and it is certainly unlikely that utility planners would persistently underforecast year after year.

Although the lead times in the model can be changed, the structure of the computer program causes errors to be introduced, if the lead time is changed by more than two and one-half years. When the changes in lead times exceed that amount, the data sets in the model get written on top of one another, and the unwary user can end up with some very strange results. Another programming problem, and one that would be more difficult to overcome, is that the model always expects nuclear plants to have longer lead times than coal plants. If, due to concern over the carcinogenic effects of burning coal, coal plants were to come to have longer lead times than nuclear, the model could not handle this without extensive reprogramming.

Environmental constraints can be handled reasonably well in REM only if they can be directly introduced as increases in the explicit cost factors in the model. For example, the requirement that utilities use low-sulfur fuels might be treated as an increase in the effective price of fuels. Similarly, the cost of pollution control equipment can be treated as an increase in the capital cost of various types of generating plants. However, REM cannot address the effect of post-combustion environmental controls (such as scrubbers) on plant availability, because availability is not a function of plant vintage. The technical characteristics of a plant of a given type are the same regardless of when the plant was constructed, and the operating characteristics do not deteriorate over time.

Another limitation is that the model cannot directly handle expectations concerning future environmental requirements. If a law is passed requiring higher quality fuels or more pollution control equipment five years into the future, that law will not even be recognized by the generation expansion plans in the model until after the full five years have passed, and then it will be another five to ten years before the new equipment is installed.

Environmental controls in the form of restrictions on the siting of new plants and transmission lines can be only partially handled by the model. Such restrictions can influence the number, but not the distribution, of generating plants. Siting restrictions are not dealt with at all in the T&D model, and the interaction between generation technologies and the T&D requirements is also not treated. Finally, environmental constraints cannot be directly imposed in REM on the end uses of energy, since the level of aggregation in the REM demand model does not show energy consumption by end-use category.

Although technology assessment (the last item in Table 3.28) is an area in which REM could, in principle, be applied, the results are likely to be less than satisfactory. There are some serious shortcomings in the structure of the generation expansion model that raise questions about the model's validity for technology-assessment applications. Perhaps the most important limitation is attributable to the fact that the present structure of REM is set up to have only one plant type for each fuel type. For example, there is only one kind of coal-fired power plant with a given heat rate, operating cost, forced outage rate, and so on. REM, however, requires the single plant type to serve two distinctly different purposes. First, the unit has to function as the state-of-the-art new plant that is offered to the generation expansion model, but then the same plant type is used as the national average plant for simulating the operation of the system. These are really two (or more) quite different plant types. Since the national average coal plant is of a much older vintage than the national average LWR, there seems to be a clear bias toward choosing to build LWRs, and this was borne out by the results of the simulation experiments. When an advanced coal plant was put up against the nuclear plant, the rapid expansion in nuclear facilities shown in the REM base case was sharply altered to show a heavy investment in coal plants.

It would be desirable to expand the number of technologies to have not just one but several state-of-the-art coal plants offered as options: a baseloaded plant; an intermediate plant; a plant which meets environmental standards through high operating costs but low investment costs (such as a plant with scrubbers); a plant which meets environmental standards through higher capital costs (such as a fluidized bed combustor); and so on. Ideally, for adequate technology assessment, each type of plant projected to be commercially available in the next twenty-five years ought to be represented in the system.

Since REM does not have any explicit representation of the T&D decision process, assessment of T&D technologies cannot be undertaken. Furthermore, the REM results would not be appropriate for assessing generation technologies that have T&D requirements which differ significantly from the historical averages. Thus, the model could not adequately analyze the effects of widespread distribution of solar units.

Many of the general limitations on the applicability of REM, as discussed in the first part of this section, apply with particular force to the area of technology assessment. Until these problems, as well as the more specific ones just mentioned, are either overcome by making structural improvements or are proven insignificant, the REM results involving the assessment of future technologies must be interpreted very cautiously.

3.6.3 Recommendations

The results of the in-depth assessment suggest a number of improvements or extensions that would expand the applicability of REM. The following list, which is by no means exhaustive, is given roughly in order of priority as we perceive it:

(1) The number of generation technologies or plant types should be expanded to model current plant vintages, state-of-the-art options, prospective new technologies, and alternative pollution-abatement configurations;

(2) An explicit and technically plausible method for dealing with capacity shortages needs to be introduced. Since this is likely to involve making some fairly strong assumptions, it may be desirable to provide the user with the option of more than one way of dealing with such a shortage;

(3) The forecasting procedures should be made more flexible since they are crucial to the behavior of REM as a whole, and yet the underlying structure cannot be estimated directly. The following options would be desirable:
   - exponential extrapolation should be available in addition to linear extrapolation;
   - the user should be able to exogenously specify the expected values to be used in the planning process;

- the planning process should have access to "future historical data;" that is, to the exogenously specified values that will be used by REM in future time periods. This will allow the model to simulate expansion planning under the assumption of perfect foresight;

(4) Retirement ages should vary by plant types;

(5) A method of modeling risk aversion should be developed so the system does not select pure optimums that rely solely one one technology;

(6) Feasibility checks should be made on the assumed plant usage factors and, in the event of sizable discrepancies, the generation expansion plans should be modified to reflect this new information. Making the retirement of plants dependent on economic factors might also be worked in at this stage if older plant types are to be modeled separately;

(7) Information from the loading of the existing system should be used to show the generation expansion optimizer the shape of the load duration gap that it needs to fill;

(8) Probabilistic effects from forced outages and effects of storage devices should be incorporated into the shape of the load duration curve;

(9) If policies affecting the electricity rate structure are to be analyzed, the pricing details in both the financial/regulatory and demand submodels will need to be expanded; and

(10) If policies affecting energy demand (such as conservation policies) are to be analyzed, the demand submodel will need to be greatly expanded. It may be that the best way of doing this is by simply inserting an entirely new submodel.

In conclusion, it should be stressed that the overall structure and behavior of REM was judged to be basically sound. It is, unfortunately, only too easy to lose sight of this, since a major objective of the assessment process is to focus on those areas in which improvements can be made in the model. In carrying out the experiments designed to test the potential structural and empirical problems, the response patterns exhibited by REM generally seemed reasonable and provided valuable insights into the issues confronting the national electric power system. REM is, unquestionably, one of the most powerful analytical tools currently available for dealing with these issues. By raising questions concerning certain aspects of its empirical implementation, we would hope that its reliability could be improved, and through the structural improvements suggested above, we would hope that its applicability could be extended. Certainly, it provides a strong basis for continuing work in this area.

CHAPTER 4

ASSESSMENT OF THE REGIONALIZED ELECTRICITY MODEL--COMMENTS

4.1 Introduction

As noted in Chapter 1, an effective model assessment provides the modelers with an opportunity to comment upon the assessment. Such a practice allows the modelers to give their perspectives on the assessment process and on details of the assessment, and allows for communication of new model developments and applications. The opportunity to comment was provided to all the modelers involved in the two case studies presented in this report. Comments were received from Paul Joskow, Martin Baughman, and Dilip Kamat.

4.2 Comments of Paul L. Joskow

I welcome the opportunity to provide a few comments relating to my experience with this model assessment effort. My perspective on the assessment is quite different from Dr. Baughman's since I have not been involved to any significant extent with the project over the past few years. Most of the burden for working with the Assessment Group has fallen on Dr. Baughman's shoulders, and I hope that all who read this report recognize the substantial amount of time and effort that he has had to put into this project. Nevertheless, I have had the opportunity to follow the progress of the project and have a number of general comments that I would like to add to the more detailed comments prepared by Dr. Baughman.

4.2.1 Are Model Assessments a Good Idea?

By and large, I think that the answer to this question is yes. As computer models are used more and more by policy makers, it is important that those using the models and those who have an interest in the results and the uses to which they are put understand the "black box" from which the "results" are being produced. While modeling efforts conducted by academics must ordinarily undergo peer review in order to secure the publication of their work, such reviews consider only certain aspects of the modeling exercise and reviewers cannot perform "hands on" examinations of the model's structure and performance. In addition, academic journals and even book publishers will rarely allow sufficient details of the model to be published to allow those who want to "use" the model to be completely satisfied. Therefore, if the model in question is of sufficient methodological or policy interest to warrant more detailed information and evaluation in order to be useful to other researchers or policy analysts, resource expenditures on model assessment are probably justified.

4.2.2 Who Should Do Model Assessment?

On the one hand, those who are most competent to do detailed model assessments are those who have had experience building related econometric/engineering models and who have a good understanding of the state of the art and the difficulties in building a useful model of a particular part of the energy system. On the other hand, it seems to me that it is unlikely that someone who is himself engaged in active research activities is likely to want to spend a great deal of time examining and assessing someone else's work. Most of us spend some time reviewing papers and book manuscripts for publication. It is a public service that we all know is crucial for the process of peer review to work and for quality publications to result. However, it seems to me that it would be difficult as a general matter to convince active researchers to devote a considerable amount of their time and effort to this type of activity. That the M.I.T. Assessment Group has been able to put together a good group of people to engage in this kind of activity should not be viewed as implying that this would be an easy thing to do as a general matter.

My own sense is that this conflict between competence and willingness to engage in model assessment activities has not made the task of the M.I.T. Assessment Group very easy. The various chapters of the report were written by individuals and not by a group. The assessment criteria vary from chapter to chapter and the willingness to incorporate suggestions made by Dr. Baughman and myself has varied widely depending on who wrote the particular section in question. Some sections clearly reflect more effort and insights than do others. Perhaps most importantly, the various people who have done the work on a particular piece of the assessment have brought to it their own preconceptions of what the "right" way to attack various modeling questions is. Such preconceptions are usually reflected in the individual's own work.

If assessments are to be a collection of individual efforts, as I believe this project was, rather than a truly group effort, I strongly believe that the various chapters should be signed by those who have written them. This has at least two advantages. First, I have the sense that when an individual is identified with a particular piece of written work, quality control is enhanced. Second, when the individual who has written the piece is known, we have a better knowledge of his own approaches to these problems and what preconceptions he brings to the task. A particular set of comments may be read completely differently when we know who has written it and what his own research background is, than when the authorship is attributed to a large group. The comments in a number of sections of this report become "obvious" once one knows who has written them.

4.2.3 The "Smoking Gun" Syndrome

My own experience in review work such as this, especially when it is conducted by a group of less-than-enthusiastic participants, is that there is a tendency to look for problems or "smoking guns" rather than to provide a well-balanced discussion of strengths and weaknesses of the material under review. I have never seen a piece of econometric work or a simulation model for which I could not identify a host of "problems" if that were the task that I set out for myself. Early drafts of some of the chapters of this report suffered from this syndrome. The best way to avoid this is to lay out clearly and completely precisely what the criteria are that are to be used in evaluating the model. A number of different criteria may be specified, but it should be clear what they are and they should be used consistently throughout the assessment. The major general problem that I have with the final report is that the criteria used differ from chapter to chapter.

4.2.4 What Criteria Should Be Used for Evaluation?

This is perhaps the most difficult problem in designing and managing an assessment project such as this. There are obviously a wide range of criteria that can be used in assessing any model. It seems to me that there are several overriding considerations that must structure the criteria. First, the questions that the model was designed to deal with must be given primary attention. If a model is assessed in the context of questions that it does not profess to deal with, the evaluation process is not likely to be particularly useful. All modeling efforts involve trade-offs between complexity, ease of utilization, and accuracy. We can get fairly accurate answers to some questions with fairly simple models. Other questions necessarily require more complex models. In this particular case, we have endeavored to make very clear what kinds of questions we thought this model is useful in answering and what kinds of questions it is not useful in answering. Let me note that we have never advertised this model as being useful as a planning or operating model for an individual utility system or as describing very short-run operating or loss-of-load characteristics for larger aggregates. Yet the discussion provided in the supply submodel chapter is structured in the context of individual utility planning and operating problems and models. I do not consider these comparisons particularly revealing unless the author can make a convincing empirical case that the use of more aggregate models leads to significant errors in predicting aggregate behavior. This argument is implied but never really carried forward in a scientific manner. Indeed, we don't even know if these utility-specific models can be used at all for the kinds of questions that are of interest to us.

The second set of considerations must be the "state of the art." How does the particular model under consideration compare with other available models that are designed to answer similar types of questions? Does it incorporate capabilities and methodological techniques that other models of its genre do not? Does it fail to incorporate modeling capabilities that are available in "competing" models? It may be that a particular model is stronger in some areas than are other comparable models, but weaker in other areas. But the state of the art must be the benchmark against which a particular type of model is assessed. No research effort such as this is the last word on the subject. Usually we try to make a few modest steps forward at a time, recognizing that there is always more work to be done and types of behavior that we do not as yet understand very well. This is the way scientific knowledge proceeds. It is always useful to be reminded of the things that are yet to be done, but it is really more useful to indicate what incremental contributions have been made.

The early drafts of this report focused far too much on some abstract ideal of what would be nice to do rather than in evaluating the model in the context of the existing state of knowledge and modeling capabilities. The latest version of the report is much improved in this dimension, but in both the supply submodel chapters and to some extent in the financial/regulatory submodel chapter a number of unreasonable expectations have been incorporated into the assessment. For example, we are told that risk-averse behavior on the part of the utilities should have been incorporated. Whether utilities are risk-averse is an interesting research question, but I am not aware of a body of research that indicates they are. Similarly, it would have been nice to have incorporated a complete model of the supply and demand for the financial instruments of electric utilities. Such a model does not exist and it seems to me that it would be unreasonable to expect that two or three of us working part-time on this project could have produced such a model or that it would have been useful to do so.

In this context, it seems to me that it would have been very useful to compare systematically the Regional Electricity Model to another similar model--for example, the electricity model in the PIES system. Does the Regional Electricity Model do things that PIES doesn't do, and vice versa? Are the problems identified in REM solved in some way in the PIES model? Without a comprehensive comparison such as this it seems to me that it is easy to focus on a few trees while missing the forest. Where problems are identified, the assessors should also endeavor not only to identify the problems but also to refer the reader to specific research results that are already in existence and could be used to improve things. If no relevant basic research exists, then the reader should be told more about the state of the art so problems that are specific to the particular model under study can be separated from fundamental gaps in knowledge. Comparisons with one or more models would also have given some meaning to the discussion related to the "accessibility" and "ease of use" of the Regionalized Electricity Model. A reader unfamiliar with this business might get the erroneous impression that it is generally an easy matter to pick up some large-scale computer model and get it running quickly. My own experience has been that it is almost impossible to get any moderately-complicated computer model to run without substantial help from those who have produced it. I don't really know whether this task was harder or easier with REM than is typically the case, but a more realistic and detailed discussion in this dimension would have been useful. Perhaps the authors have a particular model in mind--the PIES system or perhaps the Hudson-Jorgenson Model--it would be nice to know.

4.2.5 Concluding Comments

Since I believe that any assessment project such as this requires the intensive cooperation of those who built the model being evaluated, I would like to conclude with a few words about why I chose not to participate more than superficially on this project. First, I am on the

M.I.T. faculty and felt it would be inappropriate for me to get heavily involved in this type of project with my colleagues. There might have been an inclination to be too soft on us if I were constantly poking my nose in. Second, by the time this project was started, I had already decided to move on to other research projects, some in areas completely unrelated to energy. To have devoted a significant amount of time to a model assessment project such as this would have been a major professional sacrifice for someone of my age. Since the report recommends that in the future funding be provided for the modelers as well as the assessors, let me make it perfectly clear that the availability of research funding to engage in this exercise would not have led me to change my own research agenda. I suspect that others would feel very much the same way, and I fear that one of the most serious problems in conducting assessments of modeling work done by academics is to convince them to participate actively. Those who are most likely to participate are researchers who are continuing to work with the model in question, developing and improving it, and who are likely to learn something from the model assessment itself, or those who have decided to go into the business of actually selling their models. In either case, this raises difficult questions about the interrelationship of the modeler and the evaluator and necessarily creates a "moving target" problem. I see no easy way to resolve these problems. Perhaps as more experience is gained with assessments of this type some solutions will be forthcoming.

4.3 Coments of Martin Baughman

At the time I was approached about making the Regionalized Electricity Model available for assessment, we agreed that such an activity was desirable--indeed essential--for the advancement of the energy-modeling profession. At the same time, I felt that the Regionalized Electricity Model had been developed to the point where scrutiny by a third party would prove beneficial to further development and, as well, make the model transparent, and thus useful, to potential users. And though it was not without some trepidation that I offered the model for assessment, I felt at the time that this particular model would be a good trial for the assessment laboratory.

There are still areas where the modelers disagree with the M.I.T. Group's presentation of the model, and these are delineated later in this section.

Before setting forth these details, however, I would like to comment generally on the issues raised in this first independent assessment. M.I.T. has labeled and listed these as follows:

(i) the extent to which the models being assessed should be compared to similar models;

(ii) formalization of relationships among the modelers, the assessors, and the sponsors;

(iii) approaches to independent assessment; and

(iv) the nature and extent of in-depth independent assessment.

4.3.1 Individual vs. Comparative Model Assessments

What really is the distinction between individual assessment and a comparative assessment? The distinction between these two modes of assessment is not made very clear in the M.I.T. work. The M.I.T. assessment of the Regionalized Electricity Model states on pages 1-10 of the draft report: "In the present case, it has not been possible to provide a comparative assessment relating the Baughman-Joskow . . . model to other models of the same type." Although not explicit, this implies that what they attempted was an individual assessment, not a comparative assessment. But here a problem exists. The M.I.T. Group states on pages 3-54, 55 in the section entitled Electricity Generation: Model Assessment:

> "It is worth noting that the generation simulators used by electric utilities are considerably more sophisticated than the electricity generation model in REM. The utility models commonly employ probabilistic simulation, incorporate many more types of generating plants, and take into account seasonal factors. The use of an annual load duration curve in REM, although a reasonable simplifying assumption for some purposes, undoubtedly restricts the applicability of the REM results."

The passage doesn't state for what applications the model is restricted as a result of the simplifying assumptions. The passage clearly states that REM cannot be used for some of the purposes of the more detailed utility models. I don't argue with the conclusion whatsoever, but what I don't understand is why the statements exist in an individual model assessment.

Another example of the same point is the following: On page 3-12 of the M.I.T. report, the first sentence of the section on the demand submodel entitled Overview Evaluation states:

> "The REM demand submodel generally represents the state of the art in overall energy demand modeling at the time it was constructed."

The section of the report goes on to state:

> "However, REM does differ in some details from other efforts. For example, it lacks the richness of policy variables and technological specificity found in other interfuel substitution models."

The report then goes on to describe capabilities of other interfuel substitution models and contrasts these models with REM. Again, as in the case of the assessment of generation simulator, the M.I.T. Group has used other models as a reference for comparison.

The report then goes on to compare and contrast the financial/regulatory submodel in REM with the Fishbein model. Again, the M.I.T. Group has used the standard of another model to make comparisons and to facilitate the conduct of its assessment.

Now, what is the point of all this? The M.I.T. Group claims they did not do a comparative model assessment. Yet, here are three obvious examples where other models were used as a reference for comparison. I argued from the inception of this assessment activity that a comparative model assessment was the only realistic perspective that can be adopted for assessment of large-scale energy policy models. Since the M.I.T. Group has conducted its assessment, I feel even more strongly about this point, and in fact have concluded that a comparative assessment is what the M.I.T. Group really conducted. Whereas the M.I.T. Group might purport to have used reality as a frame of reference, in fact it is the understanding of reality as expressed in models--the sum total of more detailed, more specific, and other large-scale models that provide the frame of reference for their assessment. To form an informed judgment of a model's structural and empirical appropriateness in describing reality is simply to compare the model with other models. Thus, a comparative assessment was in fact conducted. I continue to believe that the real world, as an explicit frame of reference for conducting the model assessment, is an unrealizable and unarticulated standard. I think the

M.I.T. Group, at a minimum, should confess to what they are really doing. Further, I would suggest in the future that two standards of comparison should be used. The first might be the unarticulated state of the art implicitly used by the M.I.T. Group. The second is a set of explicit analytical capabilities, perhaps those used by the Department of Energy in its official policy analysis activity. After all, the Department of Energy is the public agency where energy policy in its broadest definition is analyzed.

4.3.2 Relationships among Modelers and Assessors

As a result of weaknesses in organizational relations among the model assessment group, the modelers, and the model assessment sponsor, the second in-depth assessment activity is being conducted slightly differently than was the assessment of the Regionalized Electricity Model. It became apparent in this first assessment that the demands placed upon the modeler are non-negligible. In the second model assessment (and I recommend this for all future assessments) the modeler is contractually included in the assessment to facilitate interaction and to provide recompense for the time involved.

However, a very serious question remains about what piece of computer code really represents "the model." This issue was placed under the topic of appropriate interaction between the assessment group and the modeler in this report. One position is that the model being assessed is the code that is initially handed over to the model assessors. Future interaction between the modeler and the assessor then is merely on questions of understanding. The M.I.T. Group chose to use the initial computer code in this assessment. I find this completely satisfactory for a model well fixed in its structural and empirical content, but I am hesitant to endorse this conclusion in the case of a model that is a continuing research tool--such as the Regionalized Electricity Model.

The following is a case in point: During the period that M.I.T. was conducting the assessment of the Regionalized Electricity Model, the modelers discovered a coding error in one of the statements relating to the calculations of the economics of alternative capacity types in the capacity expansion portion of the model. This "bug" in the model was corrected in our version, and we, modelers, brought this to the attention of the Assessment Group in our response to their draft overview report prepared in the summer of 1977. Yet, the M.I.T. Group chose not to correct this error in the code in their version of the model before the in-depth assessment. There are sensitivity analyses reported in the in-depth assessment where the obvious explanation for the behavior encountered is the computer bug that was brought to the assessors' attention. The behavior would have been different had the corrected version of the model been used. Should the M.I.T. Group have done the sensitivity analyses with the corrections in the computer code? They were informed of the problem by the modelers, not vice versa. Perhaps the assessment of a model should await the completion of the research of a model's development (to the satisfaction of the developers) before it is released for assessment. Or, perhaps there needs to be a follow-up assessment--say, six months after the initial assessment--that describes changes and corrections implemented in the computer code to verify and document corrections and improvements.

Finally, an equally serious question is what version of the assessment report really represents the final report. The authors were asked to respond to an overview assessment reported in the summer of 1977. This first assessment report was seriously flawed in a number of ways, and detailed comments and reactions were prepared by the modelers and sent to the assessors. Shortly thereafter, various versions of the final report were sent to me with requests for review. The first version incorporated the reports of the in-depth assessment in appendices. A few reactions to this material were delivered via telephone conversation. The modelers were then informed the report was being revised. Thus, no effort was made to review this "first draft" of the final report in more detail. Then the modelers were presented with another draft version of the report (specifically Chapters 2 and 3) transmitted on May 15, 1978, prior to a project review to be held in Palo Alto on May 25-26, 1978. No written comments were delivered to M.I.T. on this draft; however, a verbal presentation of reactions was delivered by this author at the review meeting. Requests by M.I.T. that the authors prepare a written chapter of responses to the final report where then unfilled until a complete copy of the final report, including executive summary, was available for review. This report was transmitted to me on December 12, 1978. The letter of transmittal indicated that no additional changes to this version of the report were planned and requested written comments on the report to be included as Chapter 4 in final publication. I prepared my overview and presented comments verbally at the Workshop on Energy Model Assessment held at Gaithersburg, Maryland, on January 10-11, 1979. M.I.T. participated in the workshop. After the presentations Rich

Richels, the EPRI project administrator, requested that M.I.T. make further revisions to the report, especially Chapter 1. The copy revised in response to the Richels request, is, to this author's knowledge, the copy before you. It was transmitted to me on February 7, 1979, after my reactions were presented verbally with Richels and representatives of the M.I.T. Assessment Group present at the January 10-11, 1979 workshop.

When reviewing the final transmittal after the Gaithersburg workshop, several changes in the report were apparent. The Executive Summary and Chapter 1 were changed significantly. Section 3.5 was changed significantly. References in the text to other models contained in the December 12, 1978 version of the model were deleted. The reporting process has to be more structured in the future if the modeler is to participate in a fair exchange.

4.3.3 Approaches to Assessment

The third issue raised by the M.I.T. Group comes under the heading of Approaches to Assessment. Initially, assessment of policy models was conceived as having two alternative approaches: 1) overview assessment and 2) in-depth assessment. The fundamental distinction between the two is whether or not the assessment group actually operated the model and controlled the associated data base.

At the presentation of the draft final report on the model assessment by M.I.T. at Palo Alto last year, Martin Baughman expressed his reservations about an overview and just an overview assessment. His experience was that at the stage of the activity when only the overview assessment was completed (i.e., when only documentation of the model had been reviewed), there were a large number of misunderstandings of the model behavior and the model presentation that would have been particularly detrimental to the reputation of the model and the modelers had the assessment activity been terminated at that point. There were so many inconsistencies between the assessors' understanding of the model structure and behavior and the modelers' understanding of the model structure and behavior at this stage that the modelers could not support a proposal to undertake an overview and only an overview assessment. The original conceptions of assessment needed have been altered as a result of this first experience. Does it mean that a model assessment must be a full-fledged, complete, in-depth assessment to be worth the effort? Is the independent audit plus overview a reasonable compromise? So little of M.I.T.'s final report is devoted to the independent model audit concept that it is difficult to form an informed judgment.

4.3.4 Nature of In-depth Assessment

As the M.I.T. Group points out, one way to conduct an in-depth assessment may be to exercise the capability to operate and execute the model experiments to replicate previously published results. At the other extreme, in-depth assessment might be interpreted to mean complete replication of model data, parameter estimates, computer codes, and the results of published applications. The original plan for the in-depth assessment of REM called for the following: a) checking independent data used in the model against primary sources; b) replication of estimated parameters; c) estimating new structural relations where technical results are questionable, including them in the model, and performing sensitivity analysis to determine if published analytical results might be compromised; d) verification of computer procedures and codes through analysis and recoding; and e) replication of unpublished analytical results. However, in the case of REM, the M.I.T. Group states

> "We modified our original, rather extreme concept of in-depth assessment to focus upon verification of computer code and senstivity analysis of the key parameters and independent data identified during the overview analysis."

The measure of success of the in-depth assessment is, in my opinion, somewhat inconsistent. In practice, then, the in-depth assessment really set forth only very limited objectives, and the label "in-depth" is misleading.

Sensitivity analysis cannot be a substitute for discussion of model validity. In the overview assessment of the supply portion of the model, the M.I.T. Group criticized the supply submodel as possessing several biases and not really representing a good description of electricity production and capacity planning practices. But the sensitivity analyses didn't illuminate this point. The question of how the industry would behave under the same controlled conditions imposed in the sensitivity analyses was not addressed. The behavior of the model was illuminated, but the validity of the model was not.

I think the assessment report offers much insight and an informed point of view on the Regionalized Electricity Model, but at the same time the model assessment is not necessarily entirely above reproach. The first in-depth model assessment as manifest in this report sets a high standard for future assessments.

As a result of the overview assessment of the model completed in mid-1977, several changes were implemented in the Regionalized

Electricity Model. These included a correction of all the computer "bugs" relayed to us as a result of the M.I.T. effort to reprogram the model and changes in the way the model reported capital shortages. Other changes are being made in response to recommendations of the in-depth assessment, but making thse changes might be expected to involve more time and effort than those implemented in response to the overview assessment. As a result of the assessment activity, I think that the Regionalized Electricity Model is now more transparent than it was before the assessment took place. Its behavior is better understood and its limitations are more widely known.

We now turn to a number of specific reactions we have to the M.I.T. report. In some cases our reactions are deemed necessary as a result of differences in understanding of how the model operates. In other cases, changes have been made to the model since the date of the original transmittal of a computer code to the model assessment laboratory. Thus, the comments do not apply in the current working version being used by the model developers.

Page 3-19: The report implies that provision was not made for differences in efficiency of electricity-, gas-, oil-, and coal-consuming technologies in the demand model. In fact, an average conversion efficiency for consumption devices using each of these energy forms is utilized for transforming the data into effective consumption of Btus before the model is estimated. The procedure used is described in footnote 3, page 308 of Baughman and Joskow, Energy Systems and Policy, (1976).

Page 3-20: The report states that the specification of the demand models in the residential and commercial sectors and the industrial sector, implies "trickle-down" decision making. The M.I.T. presentation of the model suggests the total energy demand calculations are made first, then followed by locational decisions, and then followed by fuel choice decisions in the model. However, all three levels of decision making are simultaneous in the model. Fuel prices determine fuel shares, the shares determine the average energy price index, the average price index determines total consumption, and the total consumption and shares determined quantities of each fuel consumed. Prices are simultaneous throughout the system.

Page 3-57: The report alludes to the problem of sudden removal of the constraint of nuclear power plant generation, called a "clipped duty cycle." Since transmitting the model to M.I.T., it has been changed to make a smooth transition from the clipped duty cycle to the maximum capacity factor used in the future. This transition is made over a five-year period, 1975-1980. In addition, the base-case data input on availability factor (AVAFAC) for light water reactors has been reduced to yield a 65% maximum capacity factor, rather than the 73% that occurred in the M.I.T. version.

Page 3-68: The M.I.T. report states:

> "For example, it would be desirable to have the model deal with loss of load probability in a direct fashion, rather than simply incorporating a prespecified margin of safety."

Though the modelers agree, we think that the incorporation of loss-of-load probability calculations into the Regionalized Electricity Model would be very space- and time-consuming. Such calculations would required detailed data on plant capacities, plant forced-outage rates, maintenance schedules, and data on coincident and noncoincident peaks for each of the geographical areas under consideration. Such a compilation of data into the model would greatly expand the required computer space and the cost of simulation.

Page 3-70: The report states:

> "The assumed load duration curve used for planning process never changes its shape, only its magnitude."

Actually, the model determines a forecasted load factor over the various planning horizons in the very same way that it forecasts fuel cost, capital costs, operation and maintenance cost, electrical energy demands, and other variables. This can be verified from the coding.

The report also states:

> "This essentially means that nuclear units being built are credited with significant load-following capabilities once they get on line."

Actually, the model assumes that hydro plus nuclear capability is credited with load following. This can be verified from the coding.

Page 3-70: The report states:

> "REM cannot be used to investigate system anticipations of expected or regulated changes in the future."

Actually, REM can be used to investigate system anticipations of expected or regulated changes in the future with simple changes in coding. Not more than five FORTRAN statements would be affected for any forecast variable in the model.

Page 3-71: The statement that REM is generally too limited in the number of plant types being modeled is a valid point. Work has been completed since the original transmittal of the model to M.I.T. to increase the number of plant types in the current working version of the model.

Page 3-74: The report states:

> "Ideally, REM should treat the transmission and distribution in an analogous fashion, i.e., have a T&D expansion submodel and a separate T&D operating cost submodel."

In fact, this is what REM does have. The point must be that REM does not explicitly incorporate lead times for T&D investment.

Page 3-74: The report states:

> "Similarly, the effect of the already existing or committed transmission-distribution system is not incorporated."

In fact, in calculating investment requirements, the existing stock of equipment is accounted for in the investment decision.

Page 3-75: The report implies that the specification of linear relationships in the T&D submodel is a serious problem. This section of the report seems to imply that the linear specifications will necessarily result in elasticity of transmission requirements with respect to demand of something greater than the "0.7 to 0.8 range" found using other than linear specifications. In fact, the linear specification of our model does not imply that elasticity equals 1.0. At the mean of the sample, the elasticity of transmission-line requirements with respect to demand is only about 0.5.

Page 3-81: In the current version of REM being used by the modelers, expected nuclear fuel cycle costs are determined in exactly the same way as other expected costs. A linear trend extrapolation for whatever nuclear lead time is being used is the basis for the forecasted variables. This change was made in our working version of the model in summer 1977. It requires a change of three computer statements.

Page 3-79: The M.I.T. report implies that the use of our linear trend extrapolation in the Regionalized Electricity Model may be inappropriate for use in future forecasts. The report states:

> "The naive techniques used in the REM load predictions modules do not seem to very accurately represent the actual situation."

We disagree.

Pages 3-97 to 3-102: This portion of the in-depth assessment requires two comments. First, the assessors make too big an issue of the way the nuclear capacity factor is handled. In none of the published results from the model is the condition evident that nuclear plants exceed the externally specified nuclear capacity factor. As a matter of practice the modelers do not accept the model output until it has been verified that the results exhibit the intent of the simulations. Only an uninformed user or assessor would attempt to use the output directly with no standard of acceptability. In fact the nuclear capacity factor is one of the outputs in the standard report of a simulation. The only way a user would not know that this constraint was placed on nuclear plants is if he did not analyze the output of the simulation.

Second, the error denoted in the footnote on page 3-60 of the report existed in the first equation of Table 3-13. This error has been purged from the modeler's version. The error was brought to the attention of the assessors in the modelers' response to the overview assessment. It was corrected in the modelers' version of the model in early 1977. It should be corrected in the assessors' version. As a result of the error in the assessors' version of the model, the sensitivity of nuclear capacity in various future years to alternative capacity factors is overstated.

Page 3-102: The first sentence of the section in Forecasting Procedure states:

> "Under conditions of exponential growth, the linear extrapolation procedures used in the REM forecasting routine can seriously underpredict future demand levels."

Depending upon what the future is relative to the past, the linear extrapolation procedure could also seriously overpredict future demand levels.

Pages 3-102 to 3-106: The errors that were discovered in the way that Alpha was included in the REM programming were brought to the modelers' attention early in the aborted effort to reprogram the Regionalized Electricity Model control. They were fixed in the modelers' version of REM in the spring of 1977.

Page 3-119, Section 3.5: As a result of feedback from the overview assessment of the model, the modelers changed the state power authority treatment. Rather than resorting to state power authority as a lender of funds, the model is now programmed so that as a last resort the dilution constraint is violated and more equity is issued. These new sales are recorded as sales below book value of equity. The effect is that increases in sales below book value raise the equity fraction, resulting in an increase in the annual capital charge rate. This has the effect of reducing the capital intensity of the economical expansion plan, the behavior advocated in Figure 3-17B.

Page 3-128: The equation has been changed in the modelers' current working version to reflect the sales-below-book-value specification dsicussed above.

Page 3-125: Fuel costs are tabulated in the model for the year as incurred. Thus, a fuel adjustment is incorporated into the model for the year. The point of the assessors that an important nonlagged factor is omitted from the model--namely the fuel adjustment clause--is thus in error. The point of tabulating fuel adjustments in annual fuel costs is also rather obscure.

<u>Page 3-129</u>: The sentence should read: "8.5% for preferred stock," rather than "5% for preferred stock."

<u>Page 3-133</u>: Page 3-129 lists the cost of debt in the base case as 9.0%. This page says the interest rate is 8.5%. It is 8.5%.

<u>Page 3-143</u>: The report states:

> "Relatively small variations in availability cause significant changes in outputs such as the mix of various types of installed generation capacity."

This behavior was the result of the error in the equation denoted in the footnote on page 3-60. When this equation is corrected, the sensitivity of the mix of various types of installed generating capacity to small variations in availability is considerably reduced.

<u>Page 3-147</u>: The problem whereby factor costs used in the generation expanison model are determined by past events and do not respond to expectations of the future has been slightly altered in the current working version of the model. A look-ahead feature with past trends and future inflation patterns is now incorporated into the static cost calculations of the generation expansion model. This feature is described in detail in the forthcoming book describing the model (available from M.I.T. Press in 1979) and has been incorporated in our working version of the model.

<u>Page 3-149</u>: The problems relating to the treatment of state power authority finance have been alleviated with the change of specification of the modelers' version of the model, wherein financing with sales of equity below book value is allowed in place of the state power authority.

Page 3-154: The current working version of the model includes the following plant types: light water reactors, existing coal-fired plants, gas-fired plants, oil-fired plants, combined-cycle plants, new coal plants with scrubbers, new coal plants without scrubbers, combustion turbines, pumped storage hydro plants, conventional hydro, geothermal plants, and a final category called "other." This revised list of technologies for generation has been added since the M.I.T. Group undertook its assessment.

References

M.L. Baughman and P. Joskow, "Energy Consumption and Fuel Choice by Residential and Commercial Consumers in the United States," Energy Systems and Policy, 1976.

M. Baughman, P. Joskow, and D. Kamat, Electric Power in the United States: Models and Policy Analysis, Cambridge Massachusetts: M.I.T. Press, Forthcoming, 1979.

4.4 Comments of Dilip P. Kamat

In their comments on the model assessment, Professors Baughman and Joskow have pointed out some of the problems they saw with the assessment process. I have not been involved with the assessment to the degree that Professor Baughman has, but I am familiar enough with the process to add a few comments.

One of the main concerns I have with the present assessment is the manner in which the assessors dealt with the problem of "assessing a moving target." The assessors claim to have "locked up" the "standard model," which was then used to carry out most of the analysis that went into the assessment. This approach is suitable for assessing commercially available models that are past the stage of development and are in a "standard" finsihed form that can be lifted off a shelf and put into operation. At the time of the assessment, REM was not in a finished stage as it was still being refined and developed. Hence, it is erroneous to claim that the assessment was carried out on a "standard" version of REM.

Some of the "flaws" that the assessors found in their version of the model have since been rectified in the current available version. The others were not perceived by the modelers as being flaws but rather as limitations on the model's applicability that the modelers have been aware of and have consistently pointed out in their previous documentation. A potential user reading the assessment may be wrongly led to believe that the model has problems in certain areas, without realizing that the assessment itself is out of date. If the assessment is expected to be circulated among potential users, this point should be emphasized. Otherwise the assessment would have served only one purpose, that of auditing a version of REM, without really contributing to its usefulness. The assessment has been more useful than that: it has helped the modelers improve REM's utility.

Another area of concern is the standard of comparison with which the assessors have compared REM. Whereas in Chapter 1 the assessors state that it has not been possible to provide comparative assessments relating REM to other models of the same type, in Chapter 3 they compare sections of REM with specialized models. REM is an integrated policy model that deals with aggregates, and the modelers have no pretentions regarding its capabilities to replicate or duplicate behavioral processes at the level of individual utilities. REM was not designed for routine use by electric utilities in the demand forecasting, capacity planning, production costing, or financial planning procedures. Comparing the submodels within REM with utility-specific or other specialized models, and then pointing out that the specialized models work differently from REM, tends to make the reader of the assessment feel that REM does not do a good enough job of simulating the electric utility industry. Whereas it is true that individual submodels in REM may be different from the more detailed utility-specific models, it should also be noted that if one were to simulate industry behavior by utilizing the models in use within the industry, the task would be next to impossible given existing constraints on data availablility and computation capabilities. The modelers had no intentions of undertaking the task of modeling the electric utility industry at that level of detail.

As the financial-regulatory submodel was developed for my master's thesis (with generous help from Professors Joskow and Baughman), I am particularly sensitive to criticisms regarding its validity and use. I do agree that an ideal financial model would compute market prices of utility stocks and bonds and simulate the capital market to determine the cost of capital for various financing instruments. However, this is a fairly formidable task and to the modelers' knowledge no suitable models have been developed elsewhere to realize the ideal or even come close to it.

In other places it has been suggested that instead of using fixed costs of debt and preferred stock with constraints on the quantity financed by each alternative, perhaps it would have been better to have provided supply functions, such as the one shown in Figure 3-17b. Implicit in such supply functions is the assumption that utilities will issue as much debt as they can until their bond rating falls and the cost of debt becomes comparable to the cost of preferred stock, at which point they switch to issuing preferred stock. In practice utilities do not use this approach. Even at times of dire financial stress most utilities have maintained debt ratios at fairly fixed levels, the national average being around 0.55. Therefore the model utilizes such a limit (in addition to interest coverage constraints) to simulate debt financing.

Elsewhere in the assessment it has been mentioned that keeping the interest rate on new debt at a constant level does not adequately represent reality. While it is true that the interest rate at which new debt is financed does vary in the short run because of short-run variations in the underlying rate of inflation, in the long run, the interest rate is pegged onto the long-run inflation rate.

As we do not have a macroeconomic model coupled to REM, the expected long-run rate of inflation is assumed to stay at a constant level into the future, and therefore the rate of interest on new debt is kept fixed too. This is not a serious drawback because, with a minor programming change, the future interest rate can be varied in any manner desired.

In his comments, Professor Baughman has addressed the SPA financing problem. I agree that the name "State Power Authority Financing" is a misnomer, but when the model was in its early stages of development a lender of last resort, very similar to the SPA in the model, was being considered by some policy makers in government. The idea was later dropped, but even so the concept of capital shortages is not unknown in regulatory economics. The SPA, or the "sale of stock below book value" (SBB, as it is now called), quantifies to a certain extent the effect of stock dilution when electric utilities are faced with financial troubles.

CHAPTER 5

A MODEL AUDIT: THE WHARTON ASSESSMENT EXPERIENCE

5.1 Outline of the Assessment Procedures

The process of assessing the Wharton energy model was, in many ways, similar to the "audit" process by which an accounting firm examines the books and annual reports of a corporation. This type of evaluation is carried out by an independent, outside party but requires the active involvement and cooperation of the entity being assessed. Furthermore, and most importantly, it is understood by all concerned that the ultimate purpose of the audit is to improve the operation and reporting procedures of the firm or modeling activity.

The Wharton model was, at the time of the audit, in the process of development. Documentation was sparse and frequently out of date, with changes being made on a daily basis. Thus, the audit was like trying to hit a moving, and sometimes dimly perceived, target. A criticism valid yesterday might be off the mark today. Although attempting to assess a model that is changing so rapidly can be very frustrating, it is at this stage of model development that an assessment is likely to have some of its greatest payoffs. The audit of the Wharton model provides a valuable prototype for one of the important functions of the model assessment process.

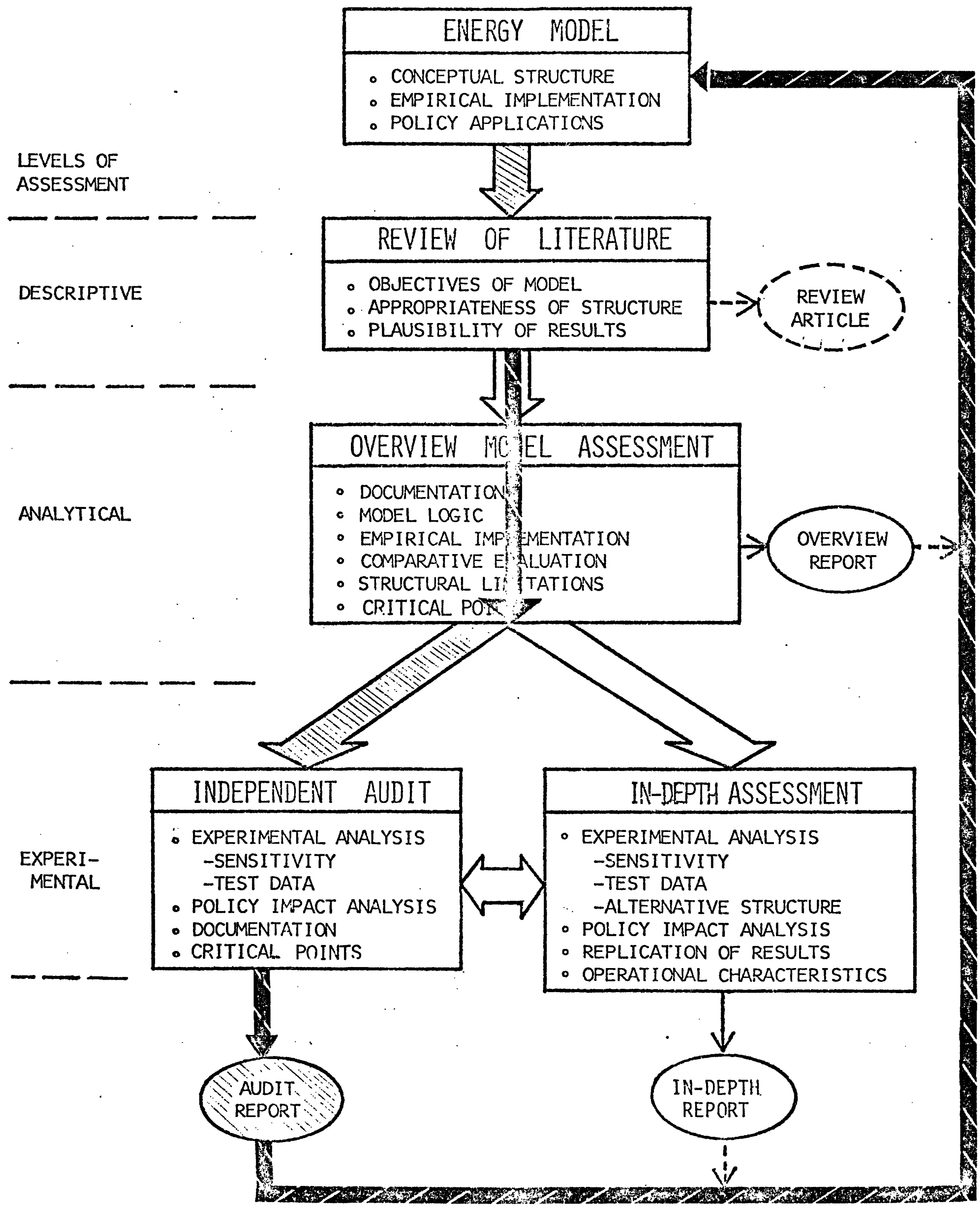
Understanding and using a large, complex computer model, particularly one still in the development stage, typically requires the active cooperation of the staff responsible for its construction. The Wharton staff was open and cooperative in providing the information needed by the assessment project. The audit of the Wharton energy model was completed in June, 1977 and was based on a version of the model that was presented to EPRI in April of that year. There have been many changes in the model since that time, and so the specific substantive findings of that assessment are now badly outdated and are not reported here.

The assessment procedures and their relation to the general assessment framework are outlined in Figure 5.0. As with any assessment, the first step in the audit was to examine all of the available documentation. The verbal descriptions of the Wharton model tended to be quite general, as would be expected for any model in its early stages, but the documentation of the mathematical relationships used in the model was quite good. The only empirical verification that was available was in the form of the statistical measures reported for individual relationships which had been derived through regression analysis. There had been no opportunity to attempt historical replication, sensitivity analysis, or similar tests of the model's properties. There was virtually no documentation of the computer programs used to implement the model since these programs were still being written.

With such sparse documentation, it was decided that an overview assessment was impractical. Instead the assessment proceeded directly to the stage of an independent audit. The audit procedures were conditioned by the two following observations:

FIGURE 5.0

WHARTON ANNUAL ENERGY MODEL
ASSESSMENT PROCEDURES



- o simulation experiments were needed to test the model's properties; and
- o the model developers were the only people capable of operating the model to carry out those experiments.

In addition to the policy simulations that had already been completed by the Wharton staff in support of an EPRI/Stanford Energy Modeling Forum study [16], about a dozen simulation experiments were conducted specifically for the purpose of generating information for the model audit. These experiments were defined by the assessment staff in consultation with the model developers and were then implemented by the Wharton staff. An important aspect of the audit procedure was that an evaluator was present when the Wharton model was run, and the precise implementation procedures were explained to him. "Looking over the shoulder" in this fashion is essential to accurate interpretation of the results produced by the experiments. The outcome of a policy experiment is frequently determined as much by the way in which the policy is introduced into the model as by the way in which the model responds. Furthermore, a great deal of information was gained from discussions with the Wharton staff concerning the ways in which the experiments might appropriately be conducted.

The audit report was completed within two months. Since it was based on a preliminary version of the model, it was distributed only to the modelers and the model sponsor (EPRI). These procedures clearly demonstrate that the audit approach is sufficiently flexible and can be completed rapidly enough to incorporate its findings effectively in the model development process.

5.2 The Structure of the Wharton Annual Energy Model

The Wharton Annual Energy Model is structured as a macroeconomic, income-determination model with an embedded input-output system. It has been developed through modifications of the existing Wharton Annual Model. One of the first changes was to expand the energy sector detail by increasing the size of the input-output table from forty-seven to fifty-nine industries. The foreign trade sector has also been expanded to give explicit consideration to specific types of energy imports and exports. More recently, improvements have been made in the method by which wholesale prices are determined. Wholesale prices now respond to changes in the cost of materials inputs as well as to changes in the cost of capital and labor.

Apart from these changes, the structure of the Wharton Annual Energy Model is conceptually very similar to that of the Wharton Annual Model. This approach has the obvious advantage of making use of a model that has already undergone extensive development and testing. Equally important, the Wharton Annual Model is used as part of Wharton's on-going forecasting and policy analysis activities. This means that the model and its results are subject to a continuous process of professional and public scrutiny. The Wharton Annual Model was recently reestimated (due to a major revision in the basic U.S. economic data), so at present, documentation of the annual model is not up to date. Since the energy model is still being developed, much of its documentation is still in the "word-of-mouth" mode. In the past, however, Wharton has made adequate documentation available for both models and underlying data bases.

Furthermore, because the annual model is used on an on-going basis, the data bases are continuously maintained and updated.

A greatly simplified flow diagram of the Wharton energy model is shown in Figure 5.1. Starting with estimates of the major final demand components (consumption, investment, etc.), standard input-output arithmetic is used to calculate the output in each of the fifty-nine industrial sectors. Next, prices, wage rates, and labor requirements are computed, which in turn determine income payments, such as personal income, profits, etc. Prices and wage rates are highly interdependent, since wage rates depend on the cost of living and prices are determined by unit labor costs. The labor force is determined primarily on the basis of the size of the population, which is exogenously projected. Unemployment is then estimated as the difference between the labor force and the labor requirements. The Wharton model contains a modest financial sector, whose primary function is to produce estimates of interest rates. As indicated by the arrows leading back to the final demand box in Figure 5.1, the system is simultaneously determined since the components of final demand are influenced by such things as incomes, industrial output, prices, interest rates, and unemployment.

While many other factors are considered in the actual model and the linkages are a great deal more complex, the structure shown in Figure 5.1 is, for present purposes, a reasonable representation of the Wharton Annual Energy Model. Table 5.1 provides a rough summary of the principal driving variables affecting the major components of the Wharton energy model. A significant characteristic of the model not indicated in the

Figure 5.1

Simplified Flow Diagram of the Wharton Energy Model

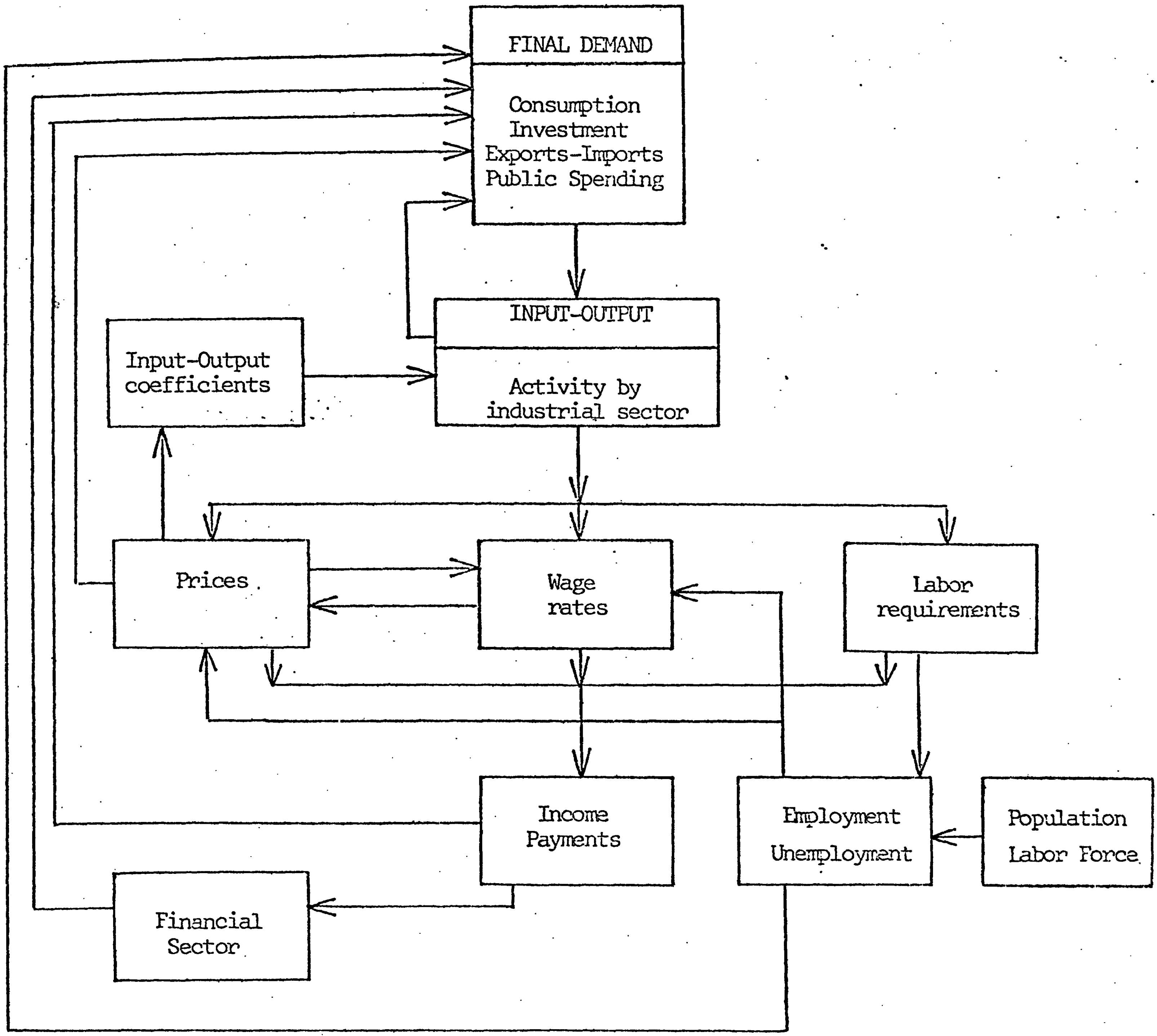


Table 5.1

Principal Driving Variables Using Wharton Model Components

1. FINAL DEMAND

A. Consumption

Disposable personal income
Price deflators for personal consumption
Interest rates (money supply/income)
Stock of autos; residential structures
Unemployment rate
Lagged consumption

Energy detail:
- fuel oil
- gas
- electricity
- gasoline and oil

B. Non-Residential Fixed Investment

User cost of capital
Price deflators for output
Output
Capital stocks

C. Residential Fixed Investment

Personal income
Price inflators
Interest rates
Population
Stock of residential structures (additions and alterations only)

D. Inventory Investment

Output (sales)
Lagged stock

E. Net Exports: exogenous

F. Government Purchases: exogenous

2. INDUSTRIAL PRODUCTION

H matrix converts final demands (G) by end-use categories (67 categories: 14 consumption, 32 fixed investment, 6 export, 8 import, inventories, and 6 government) into demands for outputs of the 59 industries.

Table 5.1 (continued)

Principal Driving Variables Using Wharton Model Components

2. INDUSTRIAL PRODUCTION (continued)

Input-output coefficients (A_{ij}) are adjusted in response to price changes.

$X = I - A)^{-1} HG$, where X is industrial production.

3. LABOR REQUIREMENTS (manhours and employment)

Output
Capital stock
Lagged employment (or manhours)

4. WAGE RATES

Price deflators
Unemployment rate
Productivity (primary metals only)
Wage rates in other industries

5. PRICES

A. Industry Value-added Prices

Rate of change of output
Unit labor cost
Unit capital cost (CCA)
User cost of capital (steel, mining, cement, utilities, chemicals, aluminum, nonferrous metals)

B. Industry Wholesale Prices

Value-added prices
Wholesale prices of inputs weighted using I-O coefficients

C. Final Demand Prices

First approximation calculated using H matrix to produce weighted average of WPI's
Autoregressive scheme on first approximation

Table 5.1 (continued)

Principal Driving Variables Using Wharton Model Components

6. LABOR FORCE

Population (exogenous trend)
Unemployment rate (lagged two years)

7. FINANCIAL SECTOR

A. Demand Deposits and Currency

Disposable personal income
Wealth
Commercial paper rate

B. Time Deposits

Disposable personal income
Wealth
Interest rate on time deposits

C. Commercial Paper Rate

Free reserves (demand and time deposits)
Discount rate

D. Bond Rate

Change in commercial paper rate

table is that many of the variables are included in the form of long distributed lags. For example, personal consumption expenditures for food and beverages depend on relative prices in the current year and in each of the five preceding years as well as the change in the unemployment rate in each of the six preceding years. The extensive use of these long distributed lags makes it difficult to readily evaluate the dynamic properties of the model. About all that can be said is that the response pattern is complex, can be erratic, and varies widely from one sector to another. A thorough evaluation of the model's dynamic properties would require detailed sensitivity analysis.

The model is predominately demand-oriented, with only rudimentary attention given to supply-side considerations and to long-run market clearing mechanisms. Because of this, use of the model is probably restricted to the near- and medium-term future. It is unlikely that in its present form the Wharton model can be used to make long-run projections for fifty or more years into the future.

The lack of market adjustment mechanisms is particularly important both in general and for energy analysis specifically, with regard to the market for capital. The investment functions used in the Wharton model take the existing stock of capital into account and are responsive to changes in the user cost of capital and output levels. However, there are no mechanisms which guarantee that the stock of the capital is in balance with the user cost of capital, or that the cost of capital is in balance with the cost of other factors. While these balancing mechanisms can reasonably be abstracted in short- and medium-term analysis, they are likely to play a vital role in long-run analysis.

A similar point can be made with regard to the market for labor. Manhours and employment are determined through the use of inverse Cobb-Douglas production functions. With this procedure labor requirements are determined solely by the level of output and stock of capital. Thus, the demand for labor does not respond at all to changes in factor prices, not even to changes in wage rates. This is a weakness in the Wharton model that could and should be corrected. It would probably be a good deal easier to make this improvement than to find a way of bringing capital markets into balance through adjustments in the saving and investment process. Making that latter extension in the model structure should, nonetheless, be a long-run objective for the Wharton model.

It is not clear from structural considerations alone how critical a limitation the lack of adequate supply-side analysis is to the user of the Wharton Annual Energy Model. To be more precise, it is not clear how far into the future the model can be pushed before the limitation becomes critical. The Wharton Annual Model was originally designed to make projections for ten or, at most, fifteen years into the future. It is over this time horizon that its performance has been most extensively reviewed and evaluated. On the other hand, the Wharton Annual Energy Model is required to make projections to the year 2000. While it is likely that the structure of the model can be modified to handle projections over that time period, no experience has yet been accumulated in using the model to make fifteen to twenty-five year projections.

Assuming that its use is restricted to the appropriate time period, the Wharton Annual Energy Model should be capable of making baseline projections of U.S. economic growth, and associated growth in the various energy sectors. One of the strong points of the model is that it has an impressive degree of industrial disaggregation. The fifty-nine industries included in the model are listed in Table 5.2. For the major energy-supplying and energy-using industries treated separately, the Wharton model is well designed for linkages with more detailed energy systems models. Also, the input-output table, which has the same level of industrial detail, provides an effective mechanism for incorporating the feedback information that would be provided by the energy models.

Another significant feature of the structure of the Wharton model concerns the method by which input-output coefficients are determined. These coefficients are not held fixed, but are endogenously determined in response to changes in input prices. While it is obviously desirable to have input-output coefficients responding to price changes rather than holding them fixed, there are some problems in the way in which this is implemented. The relationships determining the input-output coefficients are derived from constant elasticity of substitution production functions for each industrial sector. The requirement that all inputs have the same elasticity of substitution is obviously very restrictive. Furthermore, the production functions consider only materials inputs; capital and labor are not included. Demands for capital and labor are estimated in another part of the model using different analytical procedures. In both places, it is implicitly assumed that there can be

Table 5.2

Wharton Annual Energy Model Sectoring*

Sector Number	Sector Title
1	Farm, Agricultural Services, Forestry and Fisheries
2	Metal Mining
3	Coal Mining
4	Crude Petroleum and Natural Gas Liquid**
5	Natural Gas
6	Non-metallic Minerals Mining
7	New Construction, Non-farm residential
8	New Construction, Non-residential
9	New Construction, Other
10	New Constructioin, Utilities
11	Food and Beverages
12	Tobacco
13	Textile Mill Products
14	Apparel and Related Products
15	Paper and Allied Products
16	Printing and Publishing
17	Industrial Organic and Inorganic Chemicals
18	Chemicals, Other
19	Petroleum Refining and Related Industries
20	Rubber and Miscellaneous Plastic Products
21	Leather and Leather Products
22	Lumber and Wood Products
23	Furniture and Fixtures
24	Cement
25	Stone, Clay, and Glass Products, Other
26	Iron and Steel
27	Primary Aluminum
28	Primary Nonferrous Metal (excluding Aluminum)
29	Fabricated Metal Products
30	Non-electrical Machinery
31	Electrical Machinery
32	Ordnance, Other Transportation Equipment
33	Motor Vehicles and Parts

*Underlining denotes changes from existing macro model table

**Exist only as separate sectors along row.

Table 5.2

Wharton Annual Energy Model Sectoring
(Continued)

34	Instruments, Related Products, and Miscellaneous Manufacturing
35	Railroads
36	Local, Suburban, Interurban Highway Passenger Transportation
37	Motor Freight Transportation and Warehousing
38	Water Transportation
39	Air Transportation
40	Pipeline Transportation
41	Transportation Services
42	Communication
43	Electric Utilities
44	Gas Utilities
45	Water and Sanitary Services
46	Wholesale Trade
47	Retail Trade
48	Finance and Insurance
49	Real Estate
50	Services
51	Federal Electric Utilities
52	Other Federal Enterprises
53	Local Government Passenger Transit
54	State and Local Electric Utilities
55	Other State and Local Government Enterprises
56	Imports
57	Government Industry
58	Rest of World
59	Inventory Valuation Adjustment

no substitution between materials inputs and capital and labor. In addition, there is the problem that the different analytical procedures are not necessarily producing internally consistent results.

A final point is that many of the functions used in the model seem more suitable for a cyclical model than for a long-run growth model. Complex distributed lags and cyclical proxy variables are usually employed to allow a model to track short-run fluctuations in economic activity. It is not clear that they add much, if anything, to the accuracy of the long-run model, though they certainly add to its complexity and make it less transparent. There is also the question of whether an accurate representation of the short-run adjustment process will automatically produce an appropriate long-run adjustment process if the model is simply run for more years. It might be more appropriate to go directly to the estimation of relationships which, on the basis of theoretical considerations, are appropriate for long-run analysis.

Given its present stage of development, the Wharton energy model seems to be performing reasonably well. Its structural characteristics are generally appropriate for its stated purposes and it has been calibrated to trace out a plausible economic/energy system growth path to the year 2000. The Wharton staff responds positively to constructive criticism and their model seems capable of being developed into a powerful tool for energy policy analysis.

5.3 Simulation Experiments

The simulation experiments carried out with the Wharton model can be divided into three broad categories: (1) base cases; (2) economic growth responses; and (3) energy system responses. The experiments conducted within each of these areas are outlined below.

Base cases

The base case scenarios were defined by Wharton. Two base cases were examined, the difference being in the treatment of the electric utility sector. In the first case, this sector was treated as a standard input-output industry. In the second case, an explicit submodel of the utility industry was integrated into the model. This latter version of the model was used as the starting point for subsequent experiments.

Economic growth responses

Changes in labor force participation rates: The purpose of these experiments was to see how the model responded to changes in labor supply and, more specifically, to see if there were any mechanisms to bring factor markets into balance in the long run.

Increase in private investment: One of the purposes of the model is to carry out energy demand analysis within the context of an aggregate economic growth model. The purpose of this experiment was to see how the simulated economy and energy system responded to a change in the level of economic activity.

Increase in interest rates: This experiment had two major purposes: first, to see how interest rates affected aggregate growth in the Wharton model; second, to see if there were differential effects on individual industries. The second aspect was particularly interesting, since one of the outstanding features of the Wharton model is its relatively high degree of industrial disaggregation.

<u>Energy system responses</u>

Btu tax: This experiment was designed to look at the aggregate impact of a Btu tax, the effect on interfuel substitution, and the price and output responses in both the energy and non-energy industries. The experiment also showed that a valuable feature of the Wharton model is its explicit and detailed treatment of the fiscal impacts of the Btu tax.

Reduced industrial energy requirement: This experiment was intended to test how the model would respond to a technological change resulting in a reduction in the energy requirements of some of the major energy-using industries. An important feature of the experiment was to see just how such a change would, in practice, be introduced into the model structure.

Increased residential demand for electricity: Residential demand for electricity was raised in this experiment by increasing the income elasticity and decreasing the price elasticity. The purpose of the experiment was to see how this would affect growth in the electric utility industry, the growth in other energy sectors, and the growth in the overall economy.

Increases in the price of oil or coal: These experiments tested the model's general response to changes in fuel prices and, specifically, the interfuel substitution process. Given the amount of industrial detail in the model, the inter-industry pattern of impacts can also be examined.

5.4 Concluding Observations

The above outline gives some indication of the wide range of experiments that are feasible within the scope of the model audit. It is worth noting that the total effort devoted to the Wharton model audit was only about one person-month and the total calendar time was only about two months. There was, however, already a body of information available on the Wharton model as a result of other EPRI projects conducted by the National Bureau of Economic Research and by Charles River Associates. Without this information, more time and effort would have been required to complete the model audit. Nonetheless, the effort required to carry out a model audit, including simulation experiments, is appreciably less than the effort required to complete an in-depth assessment. The principal reason for this is that the assessment staff does not have to learn how to use the model in order to complete the experiments.

A model audit generally requires more effort than an overview assessment, although the additional effort may not be very substantial if detailed analysis of the computer code is necessary to carry out the overview assessment. An important feature of the audit is that it can utilize experiments to quantitatively test the critical points that can only be identified in the overview assessment. An in-depth assessment provides a set of tests that are more detailed and comprehensive, but requires considerably more time and effort than a model audit. Because of the learning process involved, an in-depth assessment is feasible only for a model that is in fairly final form. If the model is changing too rapidly, the assessment staff will be operating an outdated version of the model. By relying on the model developers to carry out the experiments, a model audit can produce useful, though less detailed, results more quickly than an in-depth assessment. It should again be stressed that it is mandatory that the auditors be present when the experiments are conducted and understand fully the implementation procedures being used. Indeed, this interaction with the model developers is one of the valuable aspects of the model audit procedures.

CHAPTER 6

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